Gas Market Report, Q1-2022

including **Gas Market Highlights 2021**

INTERNATIONAL ENERGY AGENCY

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Abstract

Global natural gas consumption rebounded by 4.6% in 2021, more than double the decline seen in 2020. The strong demand growth in 2021 was driven by the economic recovery that followed the previous year's lockdowns and by a succession of extreme weather events. Supply did not keep pace which, combined with unexpected outages, led to tight markets and steep price increases, putting the brakes on demand growth in the second half of 2021.

The year closed with record high spot prices in Europe and Asia, as natural gas supply remained very tight. The direction of short-term demand will depend on the weather during the rest of the northern hemisphere's heating season. Assuming normal temperatures, growth of the natural gas market is expected to be slowed by higher gas prices and softer economic expansion, while supply tensions may ease as offline capacity gradually returns. The exceptionally high gas (and by extension electricity) prices are likely to have an impact beyond just northern markets and the current season, with some ripple effects in both mature and emerging gas importing markets already visible.

This new issue of the quarterly *Gas Market Report* includes an overview of the main market highlights for 2021, and an analysis of recent gas market developments with a forecast for 2022.

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The season is still upon us

The year 2021 opened with cold spells that triggered price spikes in Asia in January and North America in February. These were followed by strong economic recoveries and other weather events, resulting in volume growth estimated at 4.6% year-on-year (y-o-y). The year ended with all-time high natural gas prices in the main importing markets in Europe and in Asia. The combination of demand growth and lower-than-expected supply led to the extremely tight gas market situation that prevailed throughout the final months of 2021. This was especially the case in Europe, where limited Russian pipeline supply flexibility and below average underground storage inventory levels prompted additional anxiety from the start of the heating season.

Natural gas prices have followed temperature variations over recent weeks, as the heating needs of residential and commercial customers in the main northern hemisphere markets drives gas demand. Meanwhile, the impact of weather conditions is being exacerbated by the extremely tight market situation in Europe, leading to extreme levels of price volatility. Mild temperatures, together with higher LNG inflow, moderated European prices at the start of 2022, but every new sign of colder weather or tighter supply quickly prompts price increases.

Uncertainty over prices and supply remained high as of early January, with most of the heating season still to come. Weather patterns are likely to remain the principal driver of both prices and volatility in the coming weeks, although there are also other physical, commercial and geopolitical factors at play.

Exceptionally high gas – and by extension electricity – prices have hurt consumers, utilities and wholesalers, and are likely to have a lasting negative impact beyond the current seasonal tension. The effects are not limited to Europe, as markets throughout the world experience the painful consequences of high gas prices. Emerging economies are particularly vulnerable, and are already experiencing power cuts, industrial demand destruction and potential food supply issues in the absence of affordable gas-based fertilisers.

The current market situation is a stark reminder for gas-consuming countries of the importance of implementing and updating their security of supply toolboxes, including policies to protect consumers and to optimise the use of gas infrastructure, especially storage.

Gas Market Highlights 2021

Spot prices in Asia and Europe soared to record highs in 2021 on tight market fundamentals

Natural gas prices recovered strongly in all key regions in 2021, climbing to over ten-year highs in North America and to all-time highs in Asia and Europe in Q4. This strong increase in gas prices resulted from a combination of factors: gas demand growth in 2021 was stronger than expected due to a number of weather-related factors, while gas supply faced several constraints amid higher planned and unplanned outages along the entire gas value chain. Record gas prices thus resulted from tight market fundamentals and were not a consequence of clean energy policy outcomes.

In the **United States**, Henry Hub prices almost doubled from their 2020 levels to average USD 3.9/MBtu – their highest since 2014. Combined domestic consumption and export flows grew more strongly than domestic production, resulting in a tighter market. Total demand increased by above 5% y-o-y, supported by higher residential and commercial consumption and strong growth in exports via both LNG and pipeline deliveries to Mexico. In contrast, domestic production grew by close to 2% compared to 2020, as the capital discipline of upstream companies and unplanned outages weighed on natural gas output. Henry Hub prices averaged USD 4.8/MBtu during Q4, their highest seasonal level since 2008. Pipeline imports from Canada increased by 17% y-o-y and played a key role in balancing the US gas market. This in turn provided upward pressure on Western Canada AECO prices, which saw their highest average level in Q4 since 2009 at USD 3.7/MBtu.

In **Europe**, TTF prices rose almost fivefold from their 2020 lows to reach an annual average of USD 15.8/MBtu – the highest on record. Strong demand recovery (up 5.5%) together with plummeting domestic production (down 10%), lower LNG inflow (down 4%) and reduced Russian pipeline deliveries to the European Union (down 3% y-o-y) resulted in a tight gas market. Gas storage levels standing 15% below their five-year average at the beginning of the heating season provided additional upward pressure on gas prices, which soared to all-time highs in Q4, averaging close to USD 31.5/MBtu.

Asian LNG spot prices followed a similar price trajectory to the European hubs, amid strong competition for LNG cargoes. Annual average LNG spot prices rose more than fourfold to USD 18/MBtu – again, the highest in our records. Tighter market fundamentals propelled Asian spot prices to all-time highs in Q4, soaring to an average of over USD 35/MBtu. Oil-indexed LNG prices rose by 25% y-o-y and averaged at an estimated USD 10/MBtu during 2021. Oil-indexed prices traded at a marked discount compared to spot LNG for the first time since 2009, when JKM was launched.

The strong recovery in LNG trade together with longer shipping drove up tonne-mile demand. This in turn supported spot LNG charter rates, which rose to an average of USD 100 000/day – their highest annual average in our records.

Asian and European spot gas prices displayed record-high variability and volatility in 2021…

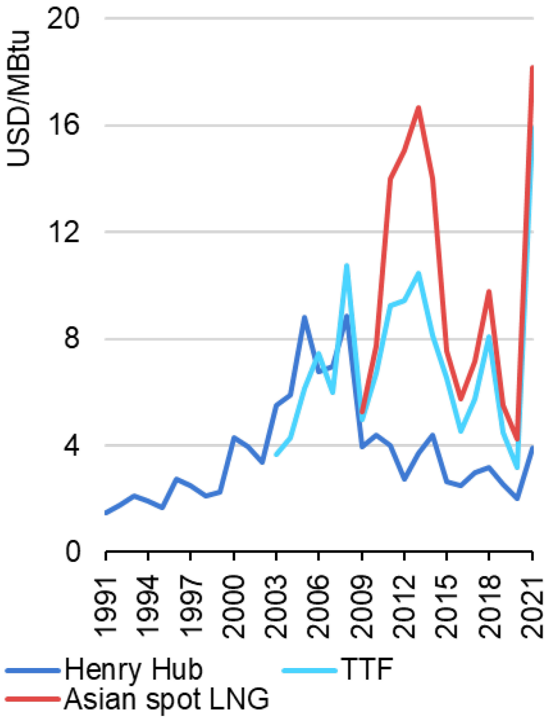
The unprecedented surge in Asian LNG spot and European hub prices has been accompanied by all-time high volatility, tight forward seasonal price spreads and an increasingly important correlation between regional gas benchmarks.

Historical gas price volatility reached its highest levels in our records both in Europe and on the Asian LNG spot market. In Europe, volatility in **TTF** month-ahead contracts averaged over 85% in 2021 – more than the double the ten-year average on the Dutch gas hub. Volatility was particularly strong in the second half of the year, reaching an all-time high of close to 200% in December. Volatility has been underpinned by a strong increase in **absolute variability**, which reached an all-time high of over 220, or an eightfold increase on its ten-year average. Strong price swings were driven by the increasingly tight gas market fundamentals, pipeline supply volatility, infrastructure uncertainty, concerns related to low underground gas storage levels, and supplier behaviour. Asian LNG spot prices displayed a similar pattern, with historical volatility averaging close to 90% during the year and absolute price variability surging to over 200 – more than eight times its five-year average. **Asian spot LNG** price volatility was partly fuelled by European gas market dynamics. Higher LNG supply outages, together with coal- and gas-fired power plant outages and extreme weather events, added further fuel to price volatility. In the United States, **Henry Hub** month-ahead prices displayed a calmer pattern, with volatility just 16% higher than its ten-year average. Absolute price variability reached 25 – its highest level since 2009. The lower US price environment combined with the United States' limited exposure to imports explains the lower variability and volatility of Henry Hub prices.

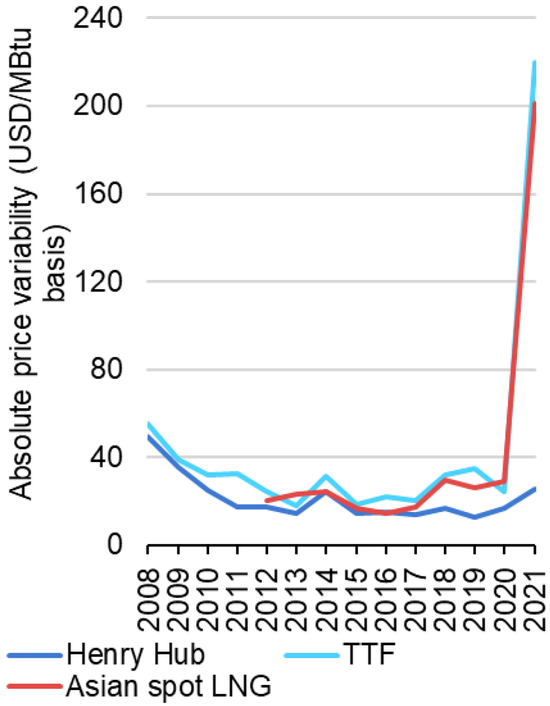
Tight summer market conditions weighed on the forward **summer–winter spreads** (front winter contracts minus summer spot prices). In Europe, seasonal price spreads fell from close to USD 1.8/MBtu in 2020 to USD 0.15/MBtu during the summer of 2021. In the United States, on Henry Hub they fell from USD 0.9/MBtu to below USD 0.13 in 2021. In contrast, Q4 gas prices indicate that out-turned seasonal price spreads (winter spot prices minus summer spot prices) were significantly higher in both markets. **The Asian and European gas benchmarks continued to display strong correlation in 2021.** Correlation between **TTF and Asian spot LNG** second-month prices reached a record 0.93 (from below 0.8 in 2019). Higher correlation is driven by the growing volumes of destination-flexible and spot LNG and marketing strategies evolving towards greater optionality. The current high correlation could be diminished in the future by unexpected, asymmetric regional supply–demand shocks. Correlation between **Henry Hub and Asian spot LNG** rose to 0.68 from below 0.4 two years ago. Correlation between Henry Hub and TTF declined in 2021 due to the strong price swings on TTF at the end of the year, reflecting Europe's particular supply situation.

…while correlation between Asian and European benchmarks grew to all-time highs

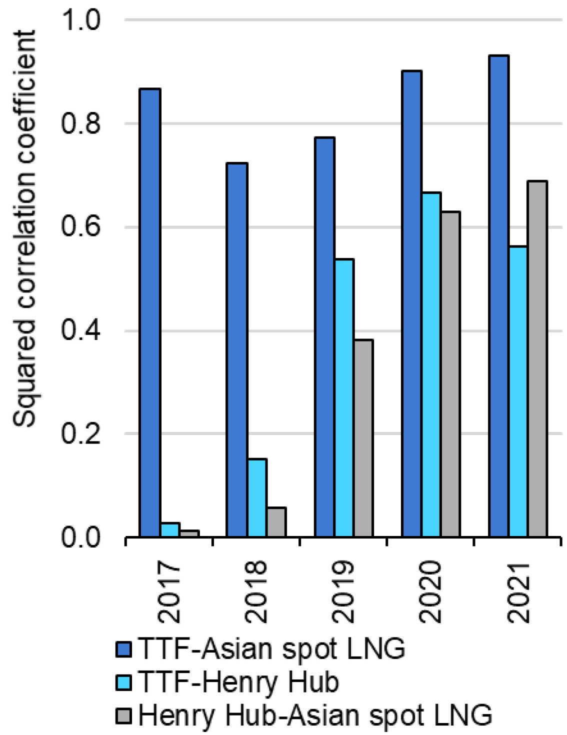
Regional natural gas prices (1991-2021)



Cumulative annual price variability* (2008-2021)



Correlation between regional bechmarks (2017-2021)



* Price variability refers to the cumulative absolute daily price variations over a period. Price volatility is the standard deviation of all the normalised daily price returns included in a given period.

Sources: IEA analysis based on historical price data from various sources, including ICIS (2022), ICIS LNG Edge.

After a strong first-half recovery, natural gas demand growth suffered from record-high prices

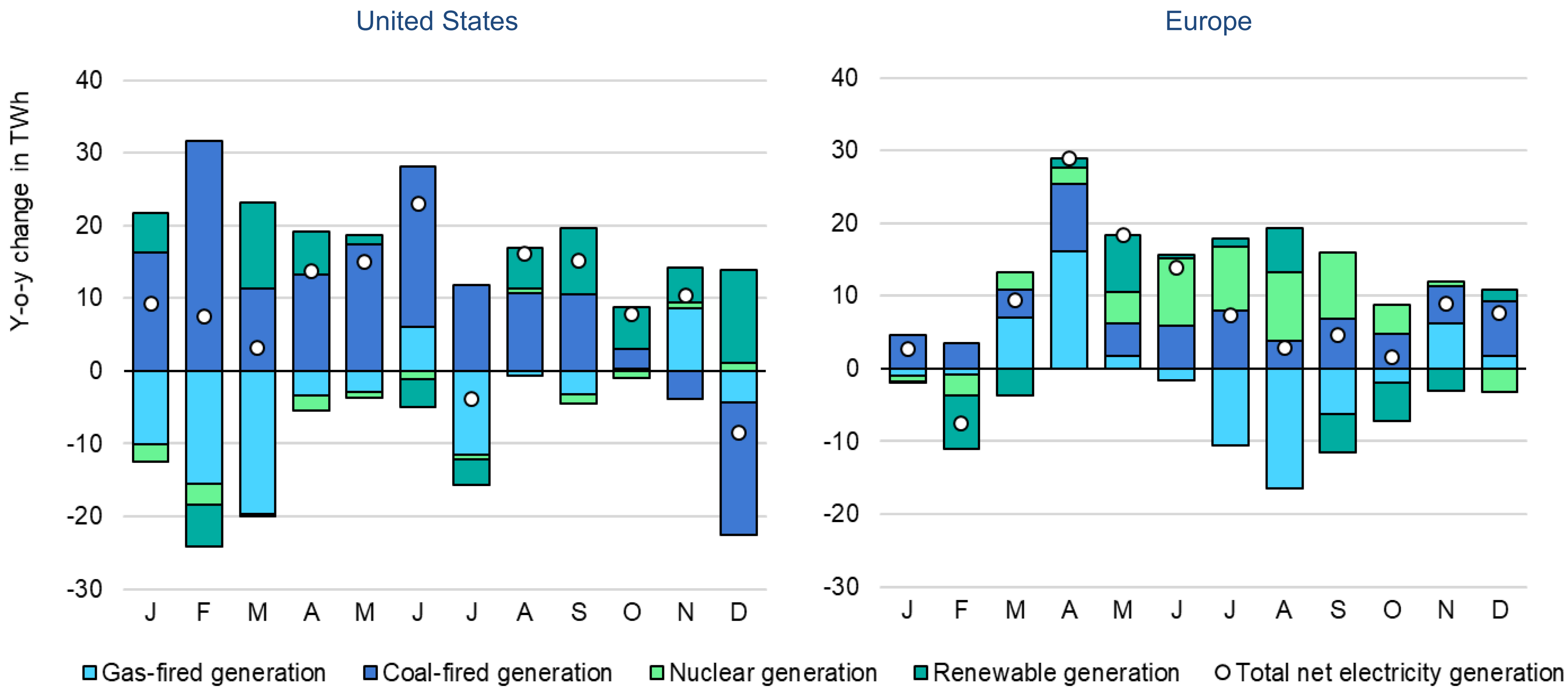
Global natural gas consumption grew at a rapid pace during the first half of 2021 on a combination of strong economic recovery from 2020 lockdowns and colder than average temperatures throughout the northern hemisphere. Preliminary figures suggest an increase in global natural gas consumption of close to 7% y-o-y during the first half of 2021. However, the progressive tightening of supply–demand fundamentals and resulting increase in natural gas prices had negative impacts on demand during the second half of the year, leading to a slowdown in growth, fuel switching and in some cases demand destruction. This resulted in an estimated 4.6% y-o-y increase in gas consumption for the whole of 2021.

Exceptionally low natural gas prices in 2020 had enabled substantial coal-to-gas switching in power generation across different regions and markets. The most visible switch occurred in the United States, but gas also grew at the expense of coal in Europe and in several Asian markets. However, this trend had already begun to change in the second half of 2020 with the progressive recovery of natural gas prices. In December 2020 US coal-fired generation showed an 8% y-o-y increase (compared with a 20% decline for the year as a whole). This continued throughout 2021, when US coal consumption for power generation showed net y-o-y increases every month from January to October, growing by an estimated 19% over the whole year, whereas gas use saw y-o-y declines almost every month and a 3% y-o-y decrease for 2021 as a whole. The shift back to coal occurred later in Europe, as a strong rebound in electricity demand in Q2 of 2021 compared to 2020 benefited both coal and gas. In the second half of 2021 rising prices worked against the use of gas in power generation. Coal-fired generation grew by over 11% in Europe in 2021, while gas-fired generation declined by 1%. Fuel switching also occurred in favour of oil for peaking needs in mature markets and as a baseload substitute in developing markets such as Pakistan and Bangladesh as LNG spot prices reached record levels in Q4.

High natural gas prices also negatively affected demand from industrial consumers, who either switched to alternative fuels or reduced output in the final months of 2021. Companies in energy-intensive sectors such as fertilisers, glass and steel had to decrease or suspend production due to high spot gas prices, especially in net importing markets such as Europe and Asia. China's industrial sector, a major source of gas consumption growth, saw negative monthly demand growth y-o-y from September. In emerging markets where gas prices are regulated, governments passed large tariff increases onto major consumers to partially fund the cost of supplying protected retail customers. They rose by 28% in Egypt and 43% in Pakistan. Cuts in the production of basic materials have ripple effects on the availability and cost of intermediate and final goods, including food products. Gas-based fertilisers had also reached record-high price levels by the end of 2021.

Flick of the switch – coal-fired generation returns as natural gas prices jump

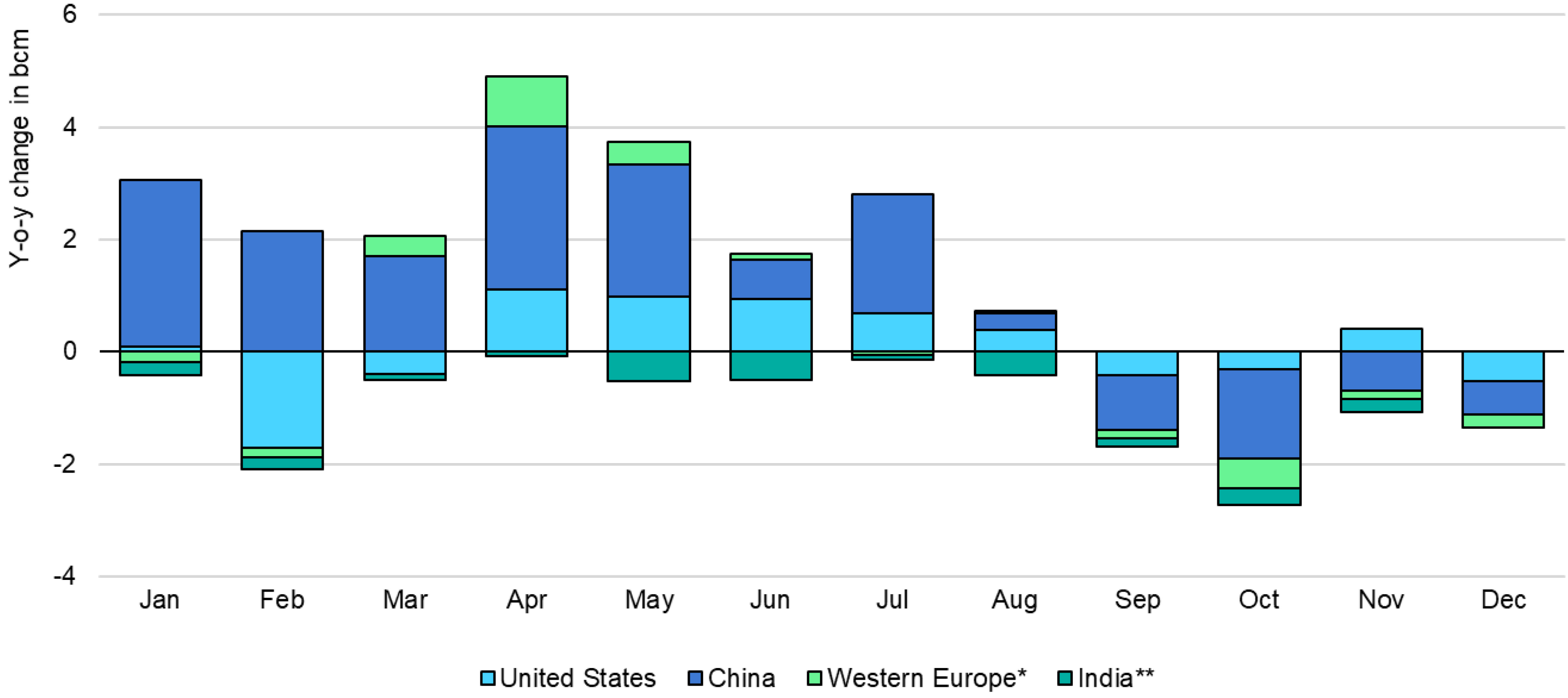
Monthly electricity generation in the United States and Europe, 2021



Sources: IEA analysis based on EIA (2022), Electric Power Monthly, US Electric System Operating Data; ENTSOE (2021), Transparency Platform.

High gas prices result in fuel switching and demand destruction in the industrial sector

Monthly natural gas consumption by industrial customers in selected markets, 2021



* Belgium, France, Italy, Spain and the United Kingdom.
** December data not available at the time of writing. Refining and petrochemicals only. Fertilisers are not included as urea producers are subsidised and are thus partially shielded from rising feedstock costs.
Sources: IEA analysis based on CQPGX (2021), Nanbin Observation; EIA (2022), Natural Gas Consumption, Natural gas weekly update; Enagás (2022), Histórico de demanda: Informe mensual; ENTSOG (2021), Transparency Platform; GRTgaz (2021), Consumption; PPAC (2022), Monthly report on natural gas production, availability and consumption.

Global gas supply has been put under pressure by outages, delays and slow pace of new FIDs

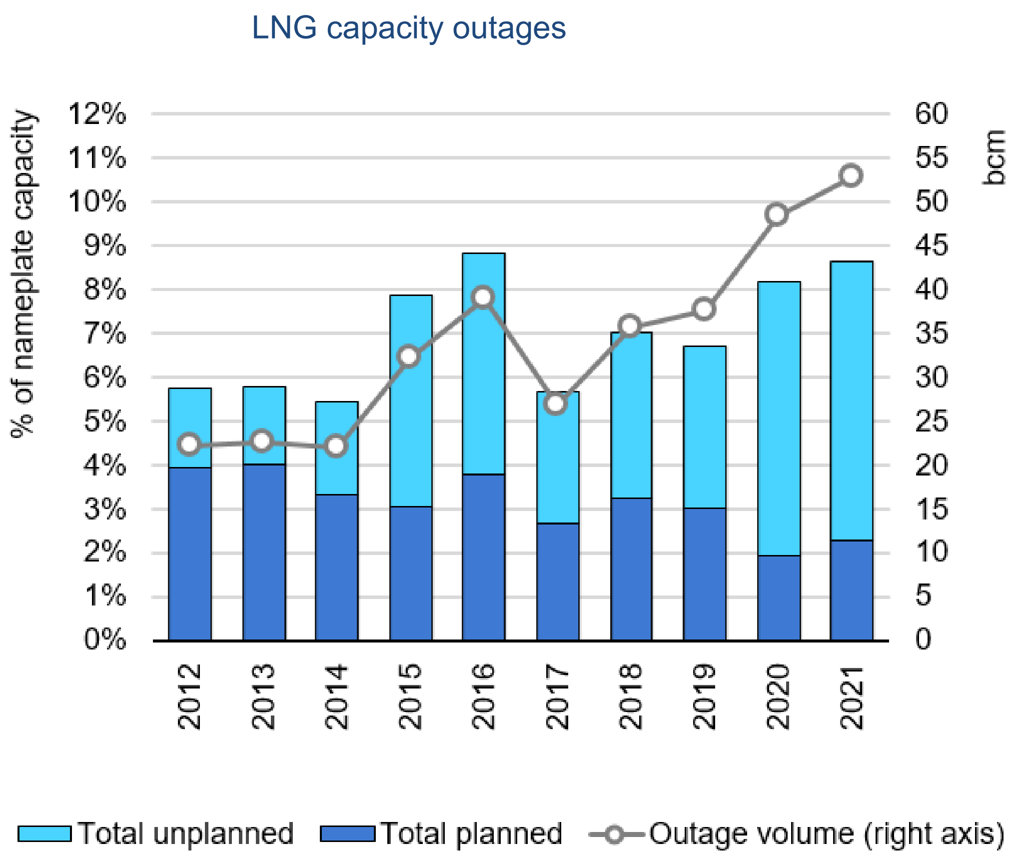
Inadequate supply – caused both by LNG capacity outages and upstream underperformance – contributed to the rapid tightening of the global gas market in 2021. Some of this was due to temporary unplanned issues and disruption to maintenance schedules caused by Covid-19 in 2020. However, in the absence of strong policies to curb demand growth to achieve net zero emission targets, gas supply adequacy could emerge as a concern for the medium term on a combination of recent LNG project delays, the relatively small number of new LNG final investment decisions (FIDs) in 2020-2021 and a structural decline in upstream spending since the early 2010s.

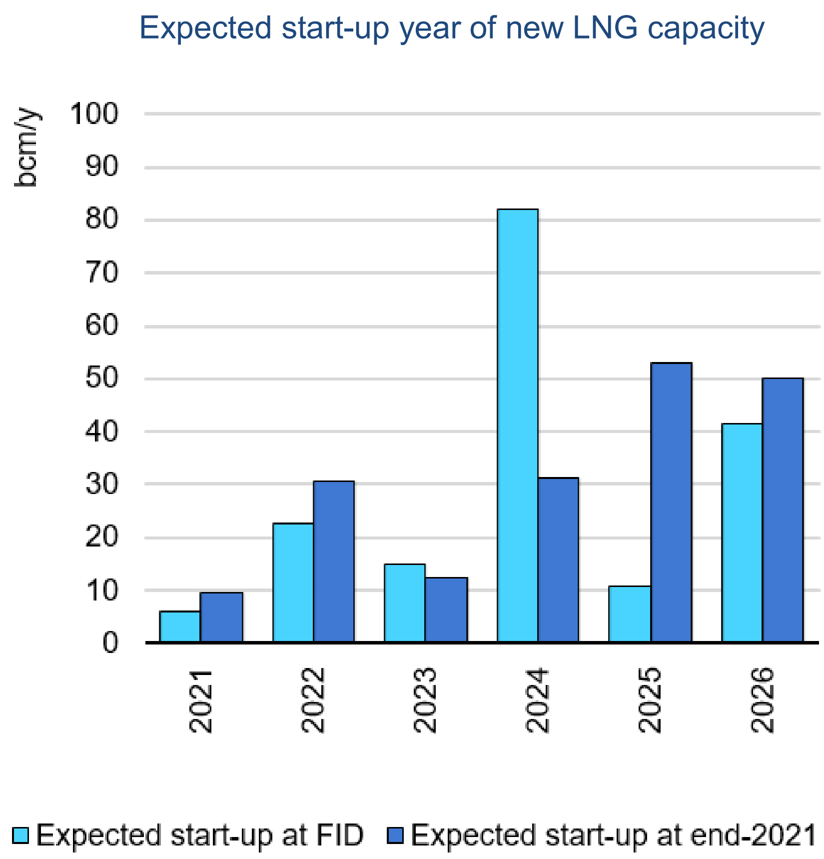
The most visible sign of supply underperformance has been the high level of LNG capacity outages, which spiked in 2020 and remained elevated throughout 2021. In 2021 the total LNG volume lost to planned or unplanned outages was 53 bcm, which is equivalent to nearly 9% of nameplate capacity and represents a 44% increase on the 2015-2020 average. About half of the LNG volumes lost to unplanned outages in 2021 (excluding the long-term disruption in Yemen) were due to upstream issues limiting feedgas availability, with the most severe incidents occurring in Nigeria, Trinidad and Tobago, and Malaysia.

Project delays could further limit supply availability in the next few years. Of the nearly 190 bcm of nameplate liquefaction capacity under construction as of early 2021, about 20% was ahead of schedule (by an average of 8 months), 35% was on time, and 45% was delayed (by an average of 14 months). Delays are especially pronounced for projects that were initially targeting full capacity by 2024, including LNG Canada, Mozambique LNG and Golden Pass in the United States.

After a record year in 2019, new LNG FIDs saw a marked slowdown in 2020-2021, with only two small single-train developments (Energía Costa Azul in Mexico and Pluto LNG train 2 in Australia) and one large-scale expansion project (North Field East in Qatar) approved in the last two years. High and volatile spot LNG prices and the recent uptick in LNG contracting activity could set the stage for additional FIDs. But the expiry of 150 bcm of LNG contracts and a projected 14% increase in uncontracted portfolio volumes between 2021 and 2024 could weaken the link between contracting and new project sanctions in this potential next investment cycle. In 2021 new contract volumes (at 90 bcm/y) were more than 50% higher than the total amount in 2020. However, only a third of the new LNG contracts in 2021 were signed with pre-FID projects (mainly in the United States). The remainder came from existing or under-construction plants or from portfolio volumes.

LNG supply outages broke new records in 2021, and project delays could be especially severe in 2024





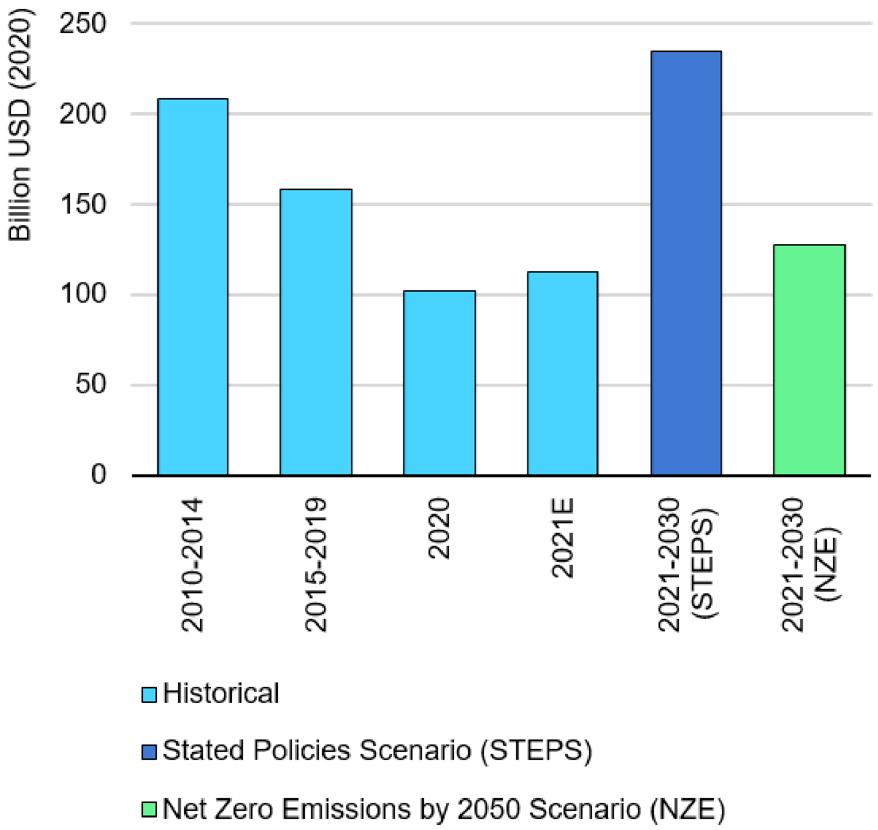
Source: IEA analysis based on ICIS (2022), ICIS LNG Edge.

Low spending levels could present challenges for upstream performance in the medium term

Upstream supply also fell short of expectations in key producing regions. In the first nine months of 2021 an estimated 11 bcm of North Sea production was lost due to extended maintenance. Gazprom, which accounts for two-thirds of Russian supply, produced 35 bcm below the company's stated capacity in 2021 despite record-high prices in Europe and strong domestic demand. US production increased by less than 2% in 2021, despite a near-doubling of the Henry Hub price from 2020 levels.

Upstream spending directed to natural gas has been on a declining trend since the beginning of the previous decade, and reached a low point (at just over USD 100 billion) in 2020 as the collapse of demand and prices in the wake of Covid-19 led to sharp curtailment of capital budgets. The recovery in 2021 is expected to remain modest, showing only a 10% increase from the previous year. At this level, gas-related upstream spending is less than half of what is required annually under the IEA Stated Policies Scenario (STEPS), and 12% lower than the amount consistent with the Net Zero by 2050 Scenario (NZE) in the 2021-2030 period. The current high price environment provides strong incentives for producers to increase upstream investment in the near term. However, demand uncertainty related to the global pandemic and the energy transition, as well as investor pressure to exercise capital discipline (in the case of US producers) and to diversify away from fossil fuels (in the case of major IOCs), could lead to a muted supplier response to high prices.

Annual upstream investment in natural gas supply



Source: IEA analysis.

Global gas trade grew by a record amount in 2021…

Initial estimates indicate that the global gas trade – LNG and long-distance pipeline flows combined – grew by over 9% (or over 85 bcm) in 2021. This represents the largest year-on-year increase on record and was largely driven by strong demand recovery in key gas importing regions, including Asia Pacific, Europe and Central and South America.

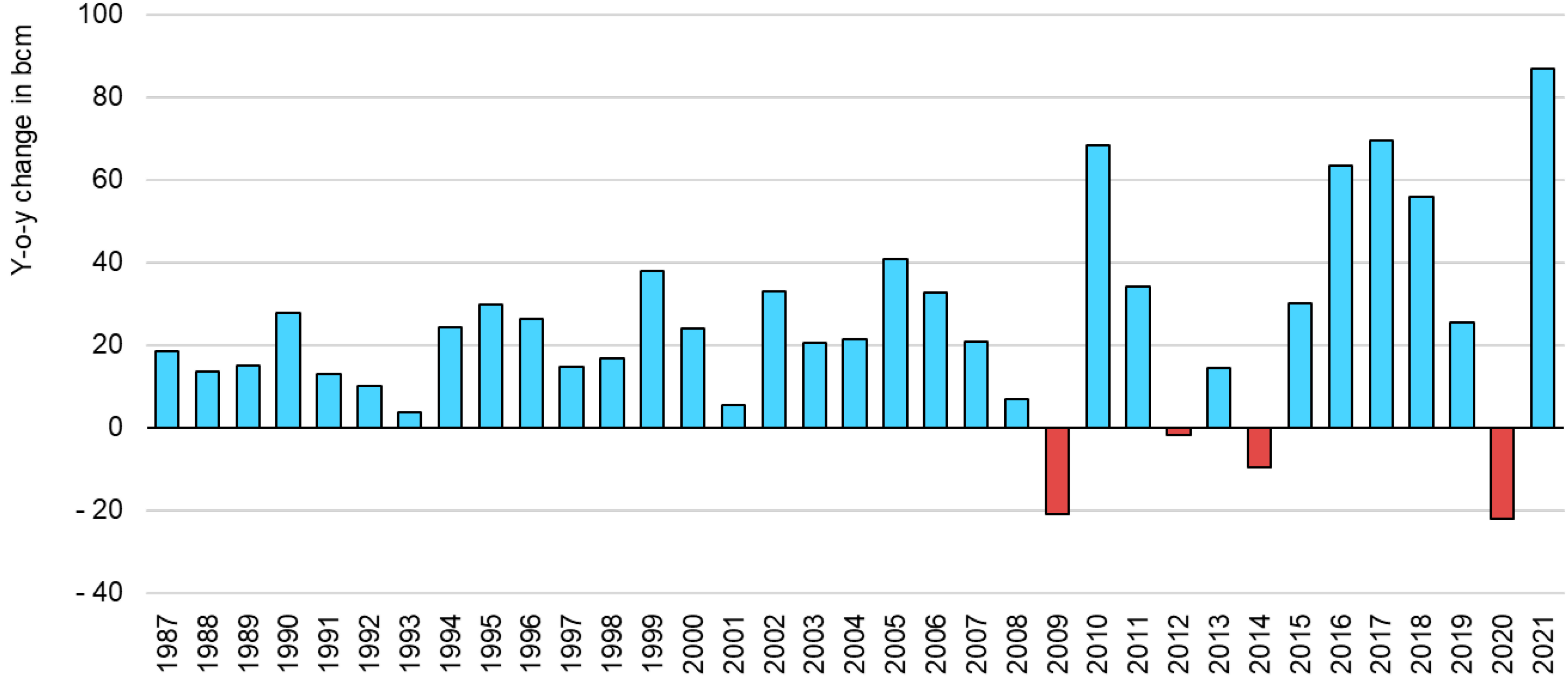
Long-distance pipeline flows surged by 12% (or 55 bcm) y-o-y, accounting for almost two-thirds of global gas trade growth in 2021 and largely recovering the losses of 2020. This strong growth was primarily driven by Europe, where pipeline imports rose by almost 11% (or over 30 bcm) y-o-y, amid a combination of higher gas demand, plummeting domestic production and lower LNG inflow. Norway's pipeline deliveries to the rest of the continent rose by 5% y-o-y, while pipeline imports from North Africa increased by over 50% y-o-y. Azeri flows into Europe surged by 20% y-o-y, driven by the ramp-up of the TAP pipeline, commissioned at the beginning of 2021. The Russian Federation's (hereafter 'Russia') pipeline exports to Europe rose by 4% y-o-y, supported by a strong increase in deliveries to Turkey, while flows to the European Union fell below 2020 levels on lower transit flows via Belarus and Ukraine. The People's Republic of China's (hereafter 'China') pipeline imports from Central Asia rose by an estimated 10% y-o-y, while deliveries from Russia via the Power of Siberia pipeline more than doubled, reaching 10 bcm in 2021. Net pipeline trade in North America rose by 11% y-o-y, driven by higher exports from the United States to Mexico, and soaring imports from Canada to the United States.

Global LNG trade expanded by 6% in 2021, a sharp acceleration from the 2020 growth rate of 1%. This import growth was led by the Asia Pacific region, which registered an 8% y-o-y increase driven by factors such as the early 2021 cold spell in Northeast Asia and a strong economic recovery. China's imports recorded a strong 17% increase, overtaking Japan for the first time in 2021 as the world's largest LNG importer. LNG imports into Central and South America soared by 69%, supported by Brazil's severe drought curtailing hydropower generation. North America continued to lead the expansion of global LNG exports, with a 51% increase in output after widespread cargo cancellations in 2020.

LNG trade growth was partly driven by spot and short-term LNG procurement, which accounted for 67% of the incremental trade volume. Consequently, the share of spot and short-term LNG in global LNG trade rose to 38% from last year's 36%. China accounted for 25% of the gross increase in short-term LNG imports, and remained the largest buyer of spot and short-term LNG. The United States retained its position as the largest provider of spot and short-term LNG in 2021 with a global share of 29%, the country accounting for almost half of gross growth in short-term sales.

…with combined LNG and long-distance pipeline trade rising by over 85 bcm

Estimated y-o-y change in combined LNG and long-distance pipeline[1] trade, 1987-2021



Sources: IEA analysis based on EIA (2022), Natural Gas: Imports/exports; ENTSOG (2022), Transparency Platform; Eurostat (2022), Imports of Natural Gas by Partner Country – Monthly Data; General Administration of Customs of People's Republic of China (2022), Customs Statistics; ICIS (2022), ICIS LNG Edge.

[1] For the purpose of this analysis, long-distance pipeline trade includes Europe's pipeline imports (from Azerbaijan, Iran, North Africa, Norway and Russia), China's pipeline imports from Central Asia and Russia, and net pipeline trade in North America.

Tight supply–demand fundamentals weighed on gas market liquidity…

Tight supply–demand fundamentals weighed on hub liquidity across all key gas markets in 2021. Hub liquidity guarantees that demand from market participants is matched by supply in a time- and cost-efficient manner without causing significant change to the price. One metric used to assess liquidity is the **churn rate**, which indicates how many times a unit of gas has been exchanged before being delivered to end consumers. Churn rates are calculated by dividing the total gas volumes traded by the total amount of gas delivered in a given gas market and time period. A higher churn rate indicates greater liquidity. Markets with a churn rate above 10 are generally considered to be liquid. Churn rates typically display a seasonal profile, edging higher during the summer and declining during the heating season on tighter market fundamentals.

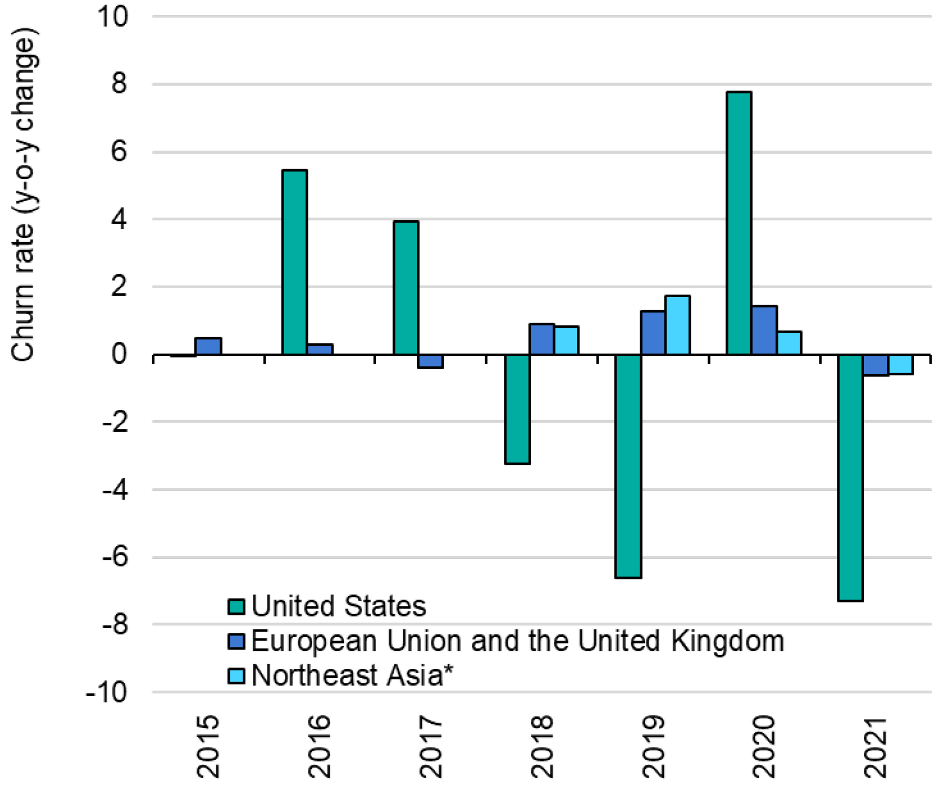
In the **United States**, volumes traded on the **Henry Hub** rose by 15% y-o-y in 2020 to reach their highest level since at least 2014. Market uncertainty and loose supply–demand fundamentals supported trading activity at a time when domestic demand was declining. This translated into a churn rate of above 50, up from 45 in 2019. In contrast, in 2021 gas volumes traded on Henry Hub plummeted by close to 20% y-o-y and fell 10% below their five-year average levels, as tighter market conditions together with the higher cost of holding positions weighed on paper trading. Consequently the churn rate fell to 45, 10% below its five-year average.

In the European Union and the United Kingdom gas trade rose by close to 15% y-o-y in 2020, largely driven by a 20% increase on the Dutch **TTF**, the region's leading gas hub. In 2021 total traded volumes in the same markets slightly declined compared to the previous year, while demand increased. Consequently, the churn rate fell marginally from 12.5 to 12. Trading on the TTF rose by 5% y-o-y, while its share of the total European gas trade increased from 70% in 2020 to close to 80% in 2021. The TTF is increasingly chosen as a hedging venue both by European and global market players seeking optionality on the European market. In contrast, traded volumes on Europe's second-largest gas hub – the NBP in the United Kingdom – plummeted by over 30%. European exchanges continued to gain traction, with traded volumes increasing by over 30%, largely at the expense of brokerages, where volumes fell by more than20%. Consequently, the exchanges' share of total traded volumes rose from 38% in 2020 to just over 50% in 2021.

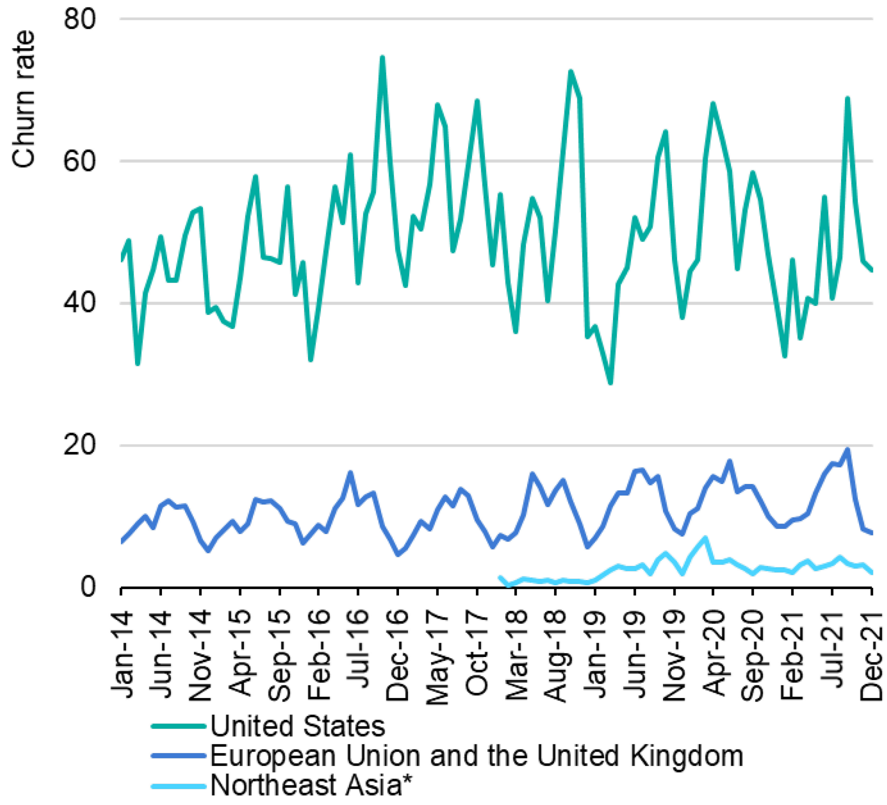
In Asia, trading in **ICE JKM** derivatives continued to increase, soaring by close to 20% y-o-y. This reflects the growing interest of market participants in diversifying their risk management and hedging strategies as they grow their spot and short-term LNG procurement. The churn rate remained low in the JKM area, hovering at just above 3.

…with churn rates declining across all key gas markets in 2021

Estimated change in annual churn rates in key natural gas markets (2014-2021)



Estimated monthly churn rates in key natural gas markets (2014-2021)



* Northeast Asia = China, Japan and Korea.

Sources: IEA analysis based on various sources, including CME (2022), Volume and Open Interest; ICE (2022), Report Center; London Energy Brokers' Association (2022), Monthly Volume Reports.

Gas market reforms continued to gather pace in 2021…

Natural gas market reforms continued to gather pace in 2021, including legislation fostering market opening and competition, measures enhancing security of gas supply, and policy initiatives to reduce the emissions intensity of gas supply and facilitate the inclusion of low-carbon gases into the gas system.

In **Brazil**, the New Gas Law was approved in April 2021, marking an important milestone in the country's New Gas Market reform programme. It provides the legal framework for the transition from a vertically integrated to a liberalised and competitive market structure. The law is based on four key principles: effective unbundling of network operators, non-discriminatory third-party access to natural gas infrastructure, establishment of an entry–exit transport system and enhanced market transparency. A decree was issued in June 2021 to guide the Brazilian National Agency of Petroleum, Natural Gas and Biofuels (ANP) in developing the market rules deriving from the New Gas Law. From January 2022 natural gas producers will have non-discriminatory access to gas processing plants and will be allowed to freely sell their output directly to the domestic market.

In China, third-party access to PipeChina's seven LNG terminals was further strengthened in September 2021, when the company auctioned off medium- and long-term import slots for the first time – for periods ranging from 5 to 20 years – to 14 successful bidders. In the same month, the state-backed Shanghai Petroleum and Natural Gas Exchange launched the country's first spot LNG price index to better reflect local market fundamentals and lessen reliance on foreign price benchmarks. The new index is reportedly supported by China's state-owned energy majors as well as the leading independent LNG importers. Earlier in 2021 the NDRC proposed a comprehensive overhaul of the country's gas pipeline tariff system, replacing the current distance-based pipeline-specific pricing with zone-based tariffs. The proposal aims to improve system efficiency and strengthen the market-based pricing of pipeline capacity across China's unified transmission grid.

India's government gave further evidence of its commitment to bring natural gas under the centrally levied goods and services tax (GST) instead of a patchwork of higher local taxes, as confirmed in a speech by Prime Minister Modi in February 2021. It is considered an important step in making gas more cost-competitive for end users. The long-anticipated unbundling of GAIL also received further government endorsement in the 2021/22 budget, which formalised a plan to set up an independent gas transmission system operator and raised the possibility of privatising GAIL's pipeline assets, although the timeline of implementation remains unclear. The bidding process for the 11th round of city gas distribution network development (covering 65 geographical areas) was formally launched in September 2021. The results are yet to be published as of late December. Gas trading has developed since the launch of the Indian Gas Exchange in June 2020, with a more than 30-fold increase in traded volumes between Q1 and Q4 2021. Nevertheless, traded volumes remain low compared to more mature European and North American hubs, totalling just under 0.2 bcm in 2021. In August 2021 the government permitted gas producers to sell 10% of their annual production on exchanges under marketing and pricing freedom.

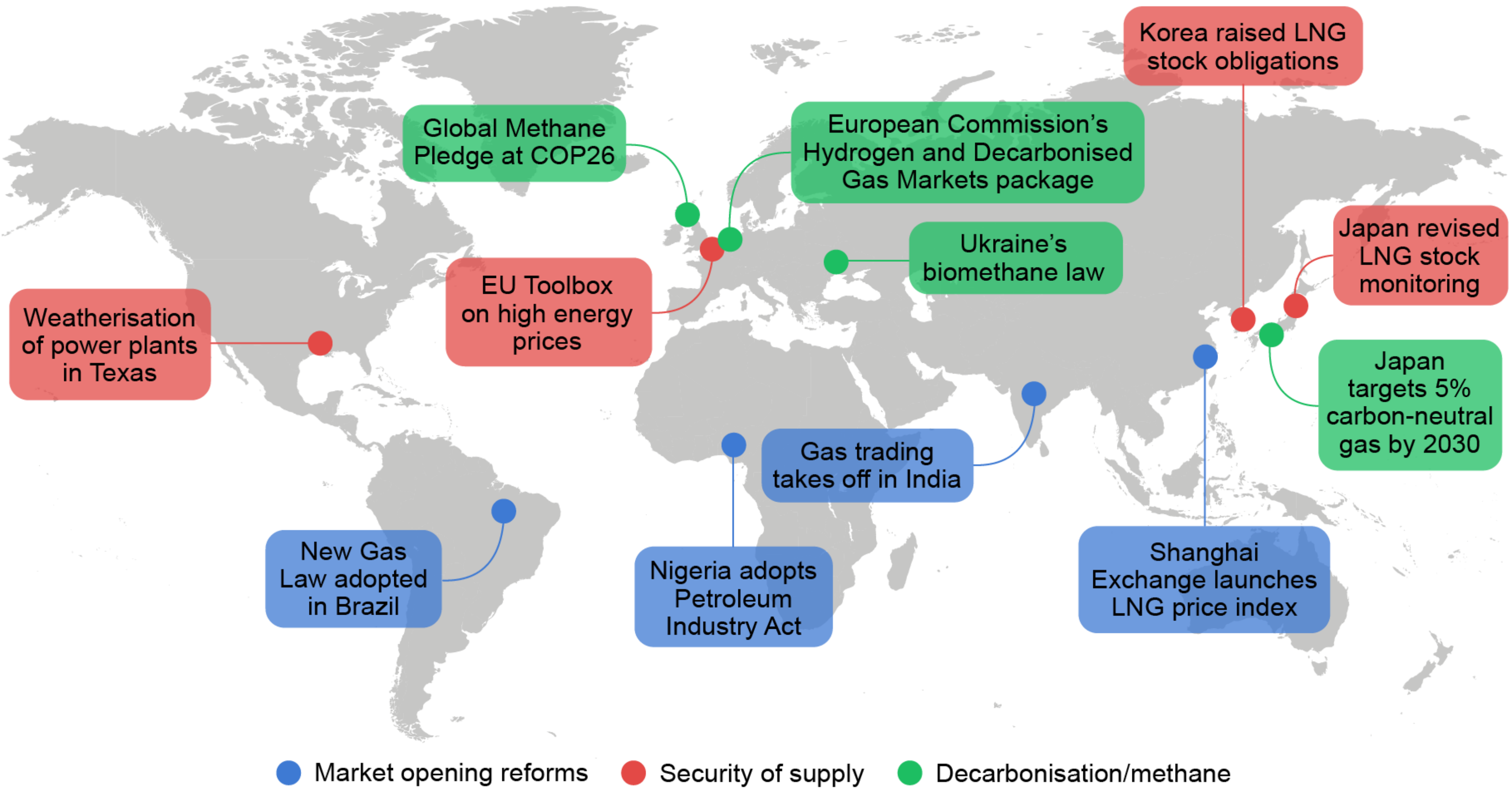
Nigeria's Petroleum Industry Act was signed in August 2021. This long-awaited law redefines the oil and gas industry's regulatory framework with the aim of incentivising private investment and competition. The act includes several specific provisions regarding the domestic natural gas market, such as the introduction of domestic supply obligations as well as major changes in gas infrastructure regulation (including a network code, access rules and pricing). It also introduces additional penalties for gas flaring and venting in order to monetise lost gas and reduce resulting pollution.

Thailand, which started liberalising LNG imports in 2019, awarded three additional licences in July 2021, bringing the total number of companies authorised to import LNG (apart from state-owned PTT) to seven. The new entrants are subject to volume caps and limited to spot market purchases for the moment, but the market regulator (ERC) plans to allow term supplies and progressively higher import volumes within the next three years.

Ukraine continued to liberalise gas prices, as regulated prices for households were abolished in August 2020 and for district heating companies in May 2021. The law enabling the transmission system operator to purchase gas on commodity exchanges for balancing purposes was adopted in July 2021. Rules related to congestion management, transparency and balancing require further alignment with the EU acquis.

…with market opening, security of supply and decarbonisation policies being the major drivers

Major gas market reforms and policy initiatives undertaken, 2021



High gas prices and security of supply concerns prompt new policy initiatives

Security of supply concerns together with the high gas prices experienced in 2021 prompted a number of policy initiatives and regulatory measures aimed at improving gas deliverability and market functioning.

In the aftermath of the January 2021 cold spell in Northeast Asia, both Japan and Korea implemented measures related to LNG stock requirements. In **Japan** the Ministry of Energy, Trade and Industry (METI) strengthened regular monitoring of LNG stocks held by power utilities and introduced new LNG procurement guidelines. In addition to these initiatives, METI held a meeting with power and gas utilities, upstream companies and trading houses to enhance co-operation during emergency situations. Power utilities' LNG inventory levels stood above the past four years' average throughout Q4 of 2021. In **Korea** LNG inventory requirements have been strengthened. Kogas is required to hold LNG inventories equivalent to nine days of demand starting from 1 October 2021, up from seven days in previous years. Furthermore, heel gas (typically equating to ~5% of storage capacity) is now excluded from the calculation of LNG inventory levels. Korea's LNG stock levels stood 5% above their five-year average in October 2021.

Following the rotating power cuts in **Texas** in February, the Public Utility Commission introduced new weather preparation rules and standards for electricity generators and transmission and distribution utilities, including better insulation and protective covering requirements. The rules set 1 December as the compliance deadline for power plants. However, power plants can request an exemption from the rules if they document their efforts to comply, explain why they have not been able to, and submit a plan to do so later. No similar measures have been adopted for natural gas supply infrastructure, although the preliminary recommendations of FERC and NERC include requirements for gas facilities to have cold weather preparedness plans. The Railroad Commission approved rules to designate certain natural gas facilities as "critical" to prevent their power supply from being cut during mandatory power outages.

High natural gas and electricity prices prompted the **European Commission** to publish a toolbox for action and support in October 2021. The toolbox includes short-term measures that member states can take to alleviate the impact of rapidly rising energy prices on consumers and industry. Regarding medium-term measures, the European Commission will consider revising the security of supply regulation to ensure the more effective functioning of gas storage sites. It will also explore the possibility of voluntary joint procurement of reserve gas stocks.

Low-carbon gas policies and industry initiatives are shaping up

The need to reduce the emissions intensity of natural gas and enable the effective integration of low-carbon gases into the broader gas system has led to new policies and industry initiatives.

The **Global Methane Pledge (GMP)** was launched in November at the 26th UN Climate Change Conference of the Parties (COP26). Over 100 countries, representing close to half of global methane emissions, have signed the GMP, thereby committing to a collective goal of reducing global anthropogenic methane emissions by at least 30% compared to their 2020 levels by 2030. It is estimated that delivering the GMP would have a similar impact on global warming as switching the entire global transport sector to net zero emission technologies. The International Energy Agency – as an implementation partner of the GMP – will provide a comprehensive hub for country-level information on sources of methane emissions in its upcoming Global Methane Tracker 2022, with a detailed view on abatement options and policy solutions for the oil and gas sector.

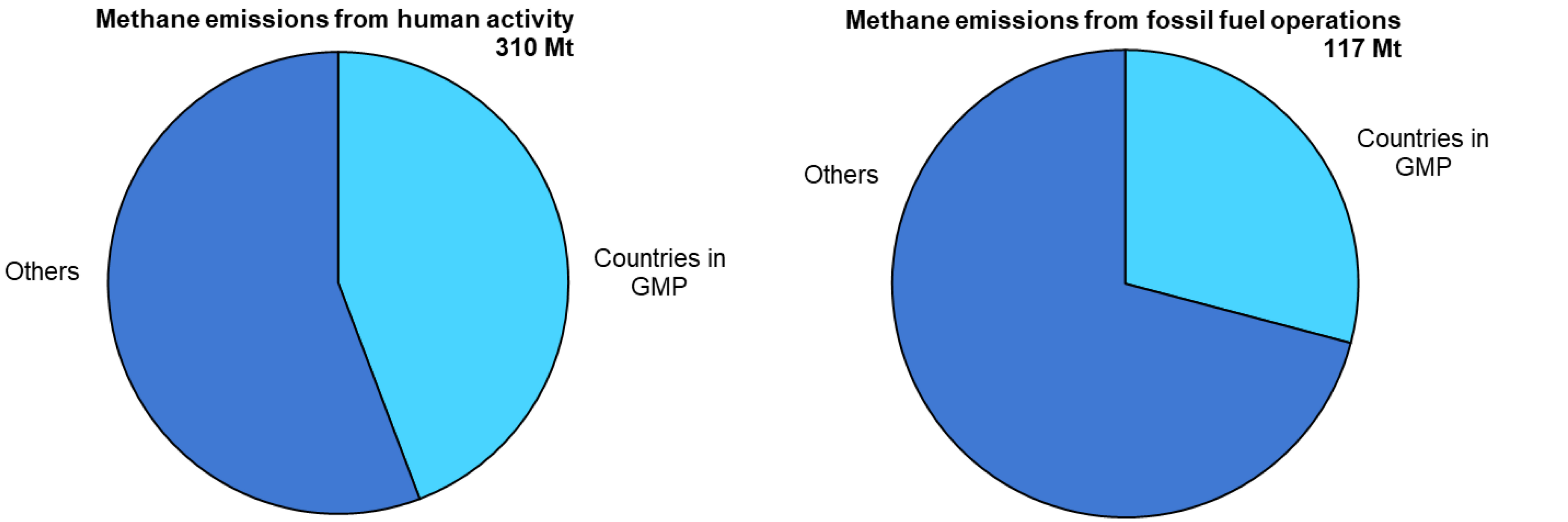
The **European Commission** published its legislative proposal for a **regulation on methane emissions reduction in the energy sector** in December 2021. The proposed regulation lays down the rules for the development of an effective measurement, reporting and verification (MRV) framework and the abatement of energy-related methane emissions through leak detection and repair programmes, and includes a ban on routine flaring and venting. The regulation foresees enhancing the transparency of methane emissions via the establishment of 1) a methane transparency database providing information on fossil fuel imports into the European Union, and 2) a global methane monitoring tool providing information on large methane emitters.

The European Commission proposal for a **regulation on conditions for access to natural gas transmission networks**, published in December 2021, lays down the foundations for the integration of low-carbon gases, including hydrogen, into the broader European gas system. The proposed regulation provides guidelines on the gradual implementation of non-discriminatory third-party access to hydrogen networks, blending limits, tariffs, network codes and operational transparency.

In **Japan** the gas industry is focusing on the development of methanation technologies to produce methane from hydrogen and CO_2. The country's **6th Strategic Energy Plan**, approved in October, sets a target to introduce into existing networks a 5% share of carbon-neutral gas (including 1% synthetic methane) by 2030 and a 90% share of **synthetic methane** by 2050.

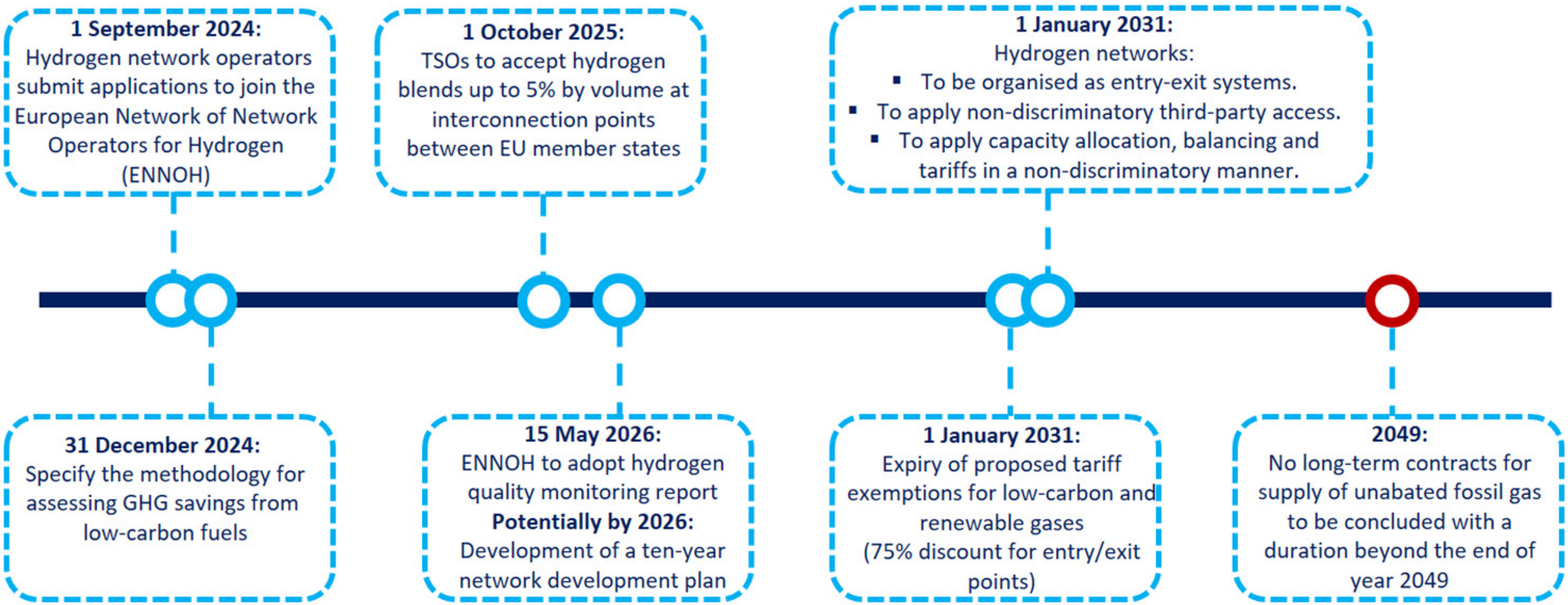
Ukraine's parliament passed a **law on biomethane** production in October 2021. The law defines biomethane, provides for non-discriminatory access to gas networks (both transmission and distribution level) and lays down the legislative grounds for the establishment of a biomethane registry.

Addressing energy-related methane emissions will be key in the implementation of the Global Methane Pledge



Notes: Reflects countries that joined the Global Methane Pledge as of 6 December 2021, including all countries within the European Union. Energy-related emissions based on IEA estimates. Data for other sectors, including waste and agriculture, are based on latest sector-level UN Framework Convention on Climate Change (UNFCCC) submissions. The 310 Mt total anthropogenic methane emissions estimate comprises data from a range of different years and is likely to be an underestimate of emissions as indicated by other sources, such as the Global Methane Budget, which provides a figure of around 360 Mt.

The European Commission's Hydrogen and Decarbonised Gas Markets Package lays down the grounds of the future European low-carbon gas market



Note: TSO = transmission system operator.
Source: IEA analysis.

Gas market update and short-term forecast

North American natural gas demand only partially recovered in 2021

Natural gas demand in the North America region grew by an estimated 0.9% y-o-y in 2021. Gas-to-coal switching in US power generation was only partly offset by a macroeconomic and weather-driven rebound for gas in other markets; demand growth in 2021 was consequently insufficient to compensate for the decline of gas in the region during 2020.

Natural gas consumption in the **United States** during 2021 was the same as 2020 due to a combination of opposing sectoral trends. Natural gas use in the power generation sector declined sharply in the initial months of 2021 due to higher fuel prices that encouraged a switch to coal, resulting in a close to 10% y-o-y decline in Q1 2021. This descent slowed in subsequent quarters, and for the year as a whole gas consumption for power generation was down by around 3%. The drop was offset by consumption increases in all other sectors. Demand from the residential and commercial sectors was the leading source of growth, estimated at above 3% y-o-y, thanks to colder than average temperatures during the first quarter and the reopening of businesses after the 2020 lockdowns. However, milder temperatures in October and December resulted in lower residential heating needs in the fourth quarter of 2021 compared to the previous year. Consumption by industrial customers also increased marginally by an estimated 0.6% y-o-y, peaking at 1.8% y-o-y in the first eight months of 2021 then declining over the last four months on softening macroeconomic trends and high natural gas prices. Gas consumption in other sectors – transport, gas networks and energy sector own use (including LNG export facilities) – also increased by about 1.4% y-o-y in 2021.

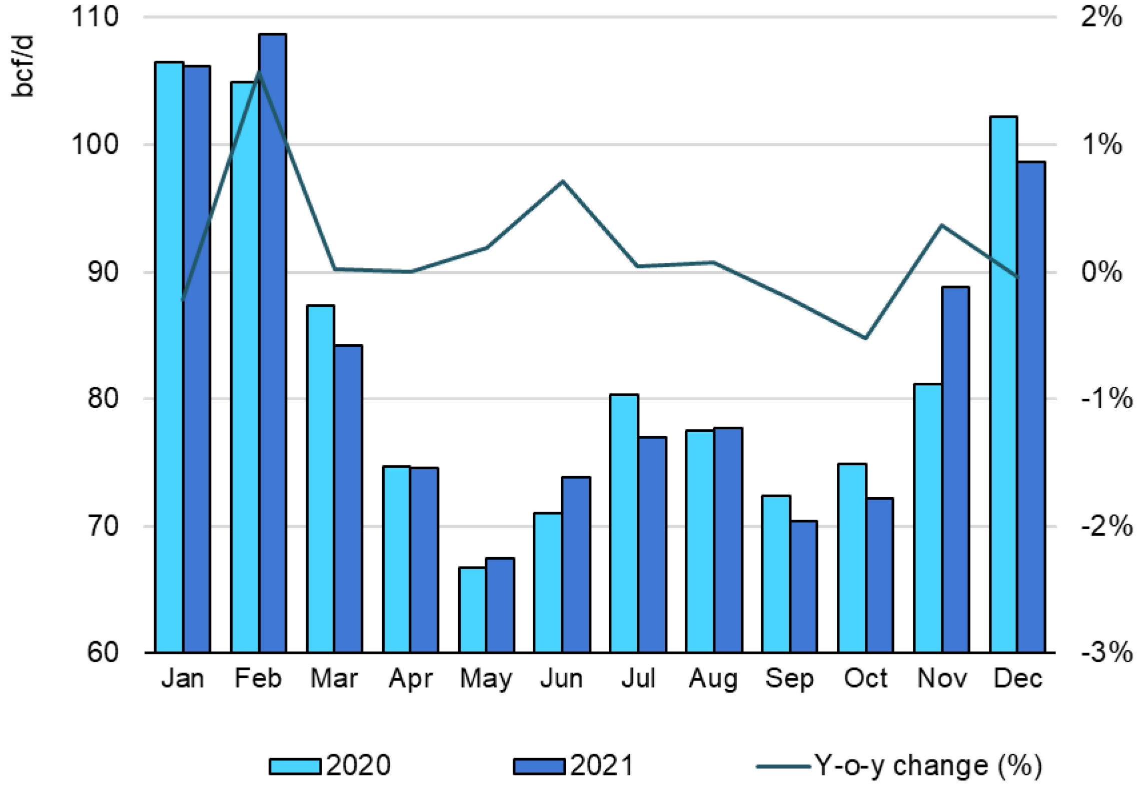
In **Canada** natural gas consumption grew by 4% y-o-y in the first ten months of 2021. This was principally driven by demand from wholesale industrial users and power generators, which increased by 6% y-o-y, whereas retail sales declined by close to 4%. Pipeline exports to the United States increased by an estimated 17% y-o-y in 2021.

Mexico's apparent natural gas consumption increased by over 1% y-o-y during the first eight months of 2021. This was principally driven by the recovery in electricity demand, which was mainly met by an increase in gas-fired generation. Domestic production decreased by about 9% y-o-y from January to September, while pipeline imports from the United States increased by close to 12% over the same period, in spite of a 6% y-o-y drop in February caused by natural gas supply disruptions in the southern United States.

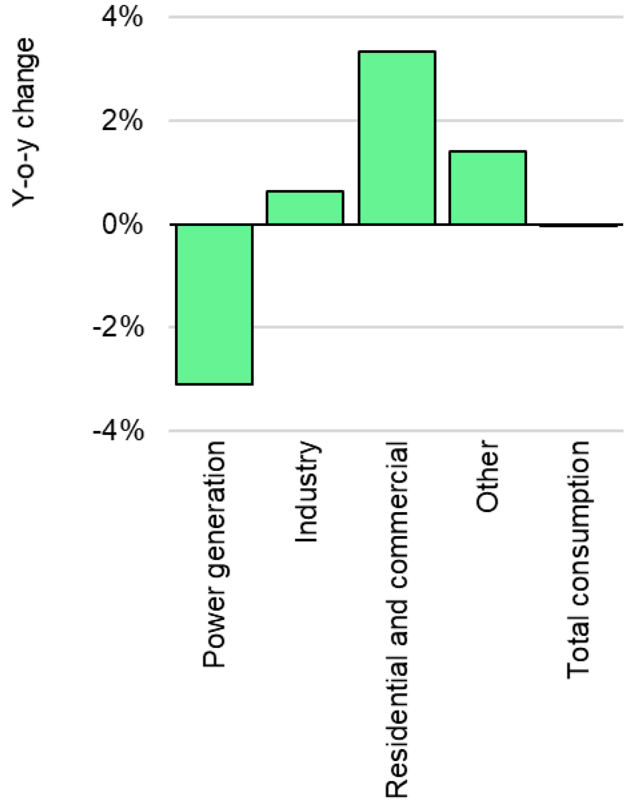
Gas consumption in North America is forecast to increase by 1% in 2022 under average weather conditions and current futures fuel prices. This would postpone to 2023 a full return to the 2019 level of total gas consumption.

US gas demand was consistent y-o-y as higher retail sales offset fuel switch in power sector

Gas consumption by month in the United States (2020 and 2021)



Gas consumption by sector in the United States, (2021 relative to 2020)



Note: bcf/d = billion cubic feet per day.
Sources: IEA analysis based on EIA (2022), Natural Gas Consumption; Natural gas weekly update; US Electric System Operating Data.

South and Central American gas demand partly bridged the 2020 gap on a strong third quarter

Brazil's gas consumption for power generation remained the region's main growth driver throughout the southern hemisphere winter, due to exceptionally low hydro reservoir levels. The country's natural gas demand grew by an estimated 23% y-o-y during the first nine months of 2021. Demand growth from the power generation sector, which soared by over 93%, was supplemented by a 15% y-o-y increase in consumption in the industrial sector. The persistence of lower than average hydropower availability kept gas-fired generation above 2020 levels in October (up 43% y-o-y) as well as in November (up 11%) despite a fall in electricity demand.

Argentina's natural gas consumption accelerated during the third quarter after flat y-o-y demand over the first half of 2021, to reach a 3% y-o-y increase during the first nine months. This growth was primarily driven by gas use in the power generation sector and by retail customers, while the industrial sector showed some decline compared to 2020.

Venezuela, the region's third largest gas-consuming country, reported a 6% y-o-y decline in its observed gas consumption during the first ten months of 2021. This decline occurred in spite of an increase in oil production – 90% of domestic gas production coming from associated fields – and is connected with higher reinjection needs to maximise crude oil output, as well as the consequences of a gas pipeline explosion late in Q1.

In **Chile** gas consumption in the power generation sector (which accounts for close to 60% of total gas demand) grew by 10% y-o-y during the first 11 months of 2021, supported by a 5% increase in total electricity demand and a 19% drop in hydro generation over the same period.

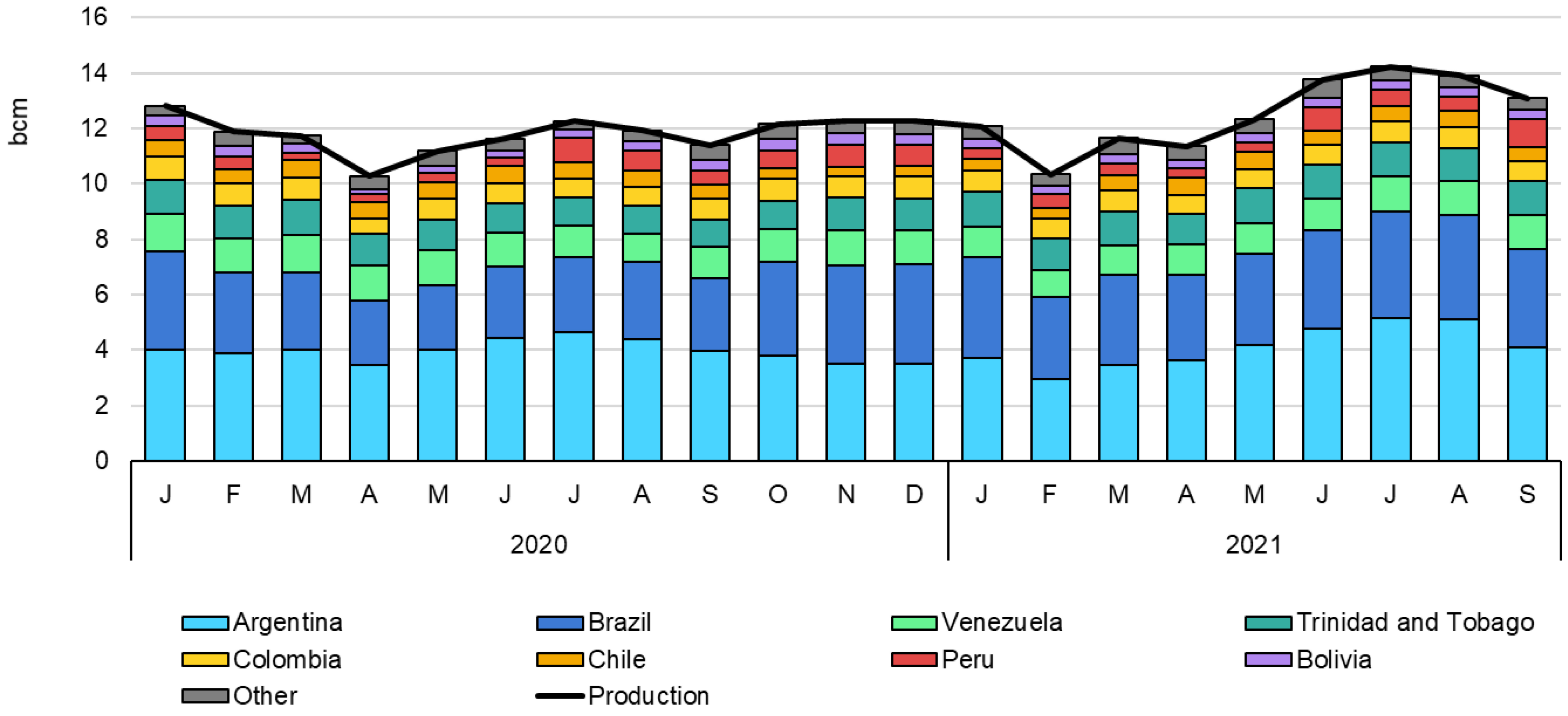
Gas demand in **Peru** increased by 12% y-o-y during the first 11 months of 2021, supported by the rebound in electricity demand and gas use in the energy sector.

Apparent gas consumption rose in **Central America and the Caribbean** in 2021 as LNG imports increased by 17% y-o-y, although high international gas prices partly eroded consumption growth, which stood at close to 25% y-o-y during the first quarter of 2021.

We anticipate that gas demand in the South and Central America region increased by an estimated 7.5% in 2021 as a whole, close to the 8% decline observed in 2020. Stable growth of less than 1% is expected for 2022 on the assumption of normal temperature and rainfall conditions.

Gas demand from Brazil's power sector remained high through the southern winter season

Monthly natural gas demand and production, Central and South America (2020-2021)



Sources: IEA analysis based on ANP (2022), Boletim Mensal da Produção de Petróleo e Gás Natural; CNE (2022), Generación bruta SEN; ENARGAS (2022), Datos Abiertos; ICIS (2022), ICIS LNG Edge; IEA (2022), Monthly Gas Data Service; JODI (2022), Gas Database; MME (2022), Boletim Mensal de Acompanhamento da Industria de Gás Natural; OSINERG (2022), Reporte diario de la operación de los sistemas de transporte de gas natural.

Despite record-high prices, European gas demand remained resilient in Q4 2021…

Following strong growth in the first half of 2021 (up by 13% y-o-y), European gas demand fell by close to 5% in Q3 amid rising prices, which led to gas-to-coal switching in the power sector. Despite record-high gas prices, **European gas demand remained resilient in Q4**, with initial data indicating that gas consumption remained flat compared to last year. **For the entire year of 2021, European gas consumption increased by an estimated 5.5%** (or 30 bcm).

Distribution network-related gas consumption rose by close to 1% y-o-y in Q4. Colder temperatures during November provided support for space heating requirements in the residential and commercial sectors, driving up gas demand by 7% y-o-y. December displayed a high variability in weather conditions, including cold spells and unseasonably mild temperatures. Altogether, residential and commercial demand rose by an estimated 1%.

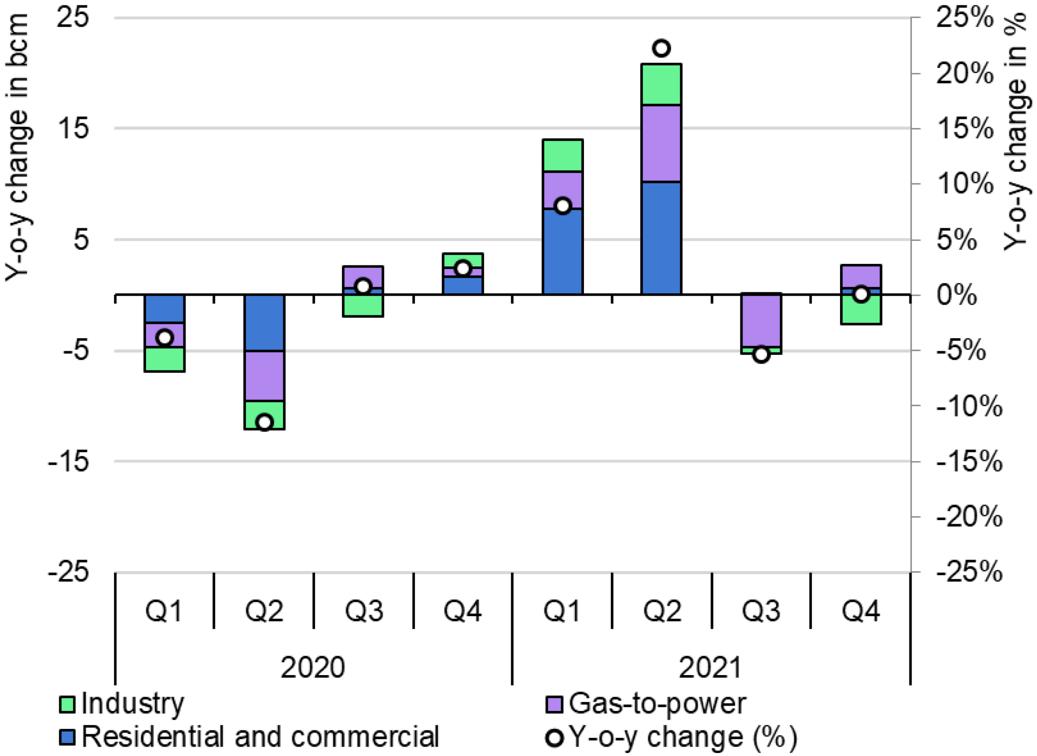
Gas demand for power production rose by close to 5% y-o-y in Q4, albeit displaying particular regional differences. In northwest Europe, record-high gas prices supported gas-to-coal switching, coal-fired power plants increasing their output by 20% y-o-y. Gas-fired generation fell by over 7%. In contrast, the steep decline in hydro generation in southern European markets (down by 30% y-o-y) led to higher gas burn in the power sector, partially offsetting the decline in northwest Europe. Gas-fired power generation rose by over 25% y-o-y in Spain and Italy (where most of the gas-to-coal switching potential has been exhausted). It continued to increase in Turkey too (up by 12% y-o-y), with natural gas retaining its price competitiveness vis-à-vis imported hard coal.

Natural gas demand in industry fell by an estimated 5% y-o-y in Q4. Record-high gas prices led to production curtailments at several major industrial plants. Gas-intensive industries, including ammonia and fertiliser production, have been the most affected. Industrial sector gas demand fell by over 10% y-o-y in Belgium, by 10% in France and by 1% in Spain during Q4.

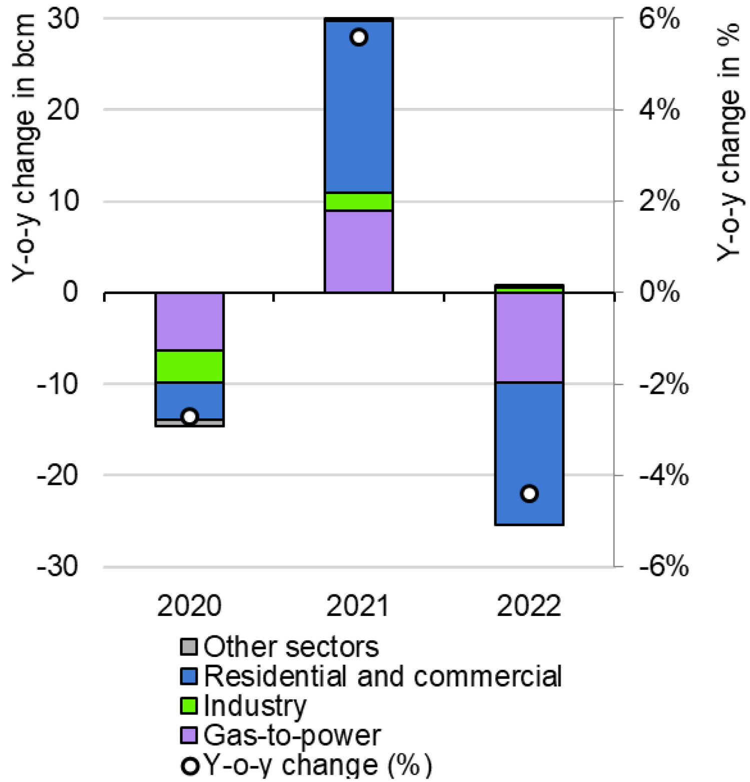
Europe's gas demand is expected to decline by over 4% in 2022. This will be partly driven by lower gas burn in the power sector, declining by 6% compared with 2021. As noted in the latest IEA Electricity Market Report, gas-fired power generation is expected to decline amid the strong expansion of renewables, while high gas prices continue to weigh on its competitiveness vis-à-vis coal-fired generation. Distribution network-related demand is foreseen declining on lower space heating requirements, assuming a return to average weather conditions in Q1 and Q2 after an unseasonably cold spring in 2021. Gas demand in industry is expected to continue to recover, reaching close to its pre-2020 levels.

…with European gas consumption rising by an estimated 5.5% in 2021

Estimated change in Europe's quarterly natural gas consumption (2020-2021)



Change in Europe's natural gas demand (2020-2022)



Sources: IEA analysis based IEA analysis based on Enagas (2022), Natural Gas Demand; ENTSOG (2022), Transparency Platform; EPIAS (2022), Transparency Platform; Trading Hub Europe (2022), Aggregated consumption.

Asia's demand recovery continued with regional disparities in 2021; 2022 to see slowing growth

Asia's gas demand increased by a robust 7% in 2021. However, there were large geographic and temporal disparities in the region's gas consumption profile throughout the year. Northeast Asia accounted for more than 82% of the net growth in Asia, driven by a combination of cold winter and hot summer weather, sporadic droughts and a strong post-Covid recovery. China alone was responsible for 69% of Asia's total consumption growth in 2021; Korea contributed another 11%. Meanwhile, growth in South and Southeast Asia remained modest as high LNG prices and resurgent waves of Covid-19 dampened demand. The pace of growth across Asia also decelerated markedly in the second half of the year. In the January to July period, the combined demand of the top five gas markets in Asia (China, Japan, India, Korea and Thailand) increased by a remarkable 14% y-o-y. The corresponding y-o-y growth rate for the August to December period is estimated at close to zero, as high prices, slowing economic growth and weather normalisation moderated consumption. In 2022 Asia's gas demand is projected to increase by 5%, driven by China, emerging Asia and India, which are expected to account for 66%, 26% and 10% of the region's net demand growth, respectively, while Japan and Korea are expected to see modest declines.

China's gas demand increased by an estimated 12% in 2021. Consumption growth was especially robust in the January to July period (up 19% y-o-y) due to cold winter weather in Q1, low hydro availability in the spring and a hotter than average summer in southern China, which boosted power and city gas demand in particular. Industrial demand also remained strong in the first seven months of 2021 thanks to the sharp rebound in economic activity. However, there was a marked slowdown in China's gas demand trajectory from Q3 when high LNG prices led to demand destruction in some industries (e.g. ceramics) and transport, while slowing GDP growth and government-mandated power cuts put pressure on industrial activity in general. Coal shortages and a cold start to the winter provided some support to gas demand in the power and residential sectors at the beginning of the fourth quarter. In 2022 demand growth is expected to moderate to an annual rate of 8% due to slowing economic growth, high import prices (at least through to Q1 2022) and the expected normalisation of seasonal patterns following the weather extremes of 2021.

India's gas demand is expected to have increased by 5% in 2021. In the first 11 months of the year, total consumption was up by 5% y-o-y. This was led by the city gas segment, where a strong recovery from 2020 lockdowns and the continuing rollout of distribution networks (despite Covid-related delays) boosted demand by 40% y-o-y in the January to November period. This was partly offset by declining demand in the refining and petrochemical sectors, where some operators switched from gas to liquid fuels in response to surging LNG prices, and in power generation, where gas burn fell with the rising price of LNG from mid-2021. Gas use in the fertiliser sector was up by 7% y-o-y as India's last naphtha-based urea plants converted to natural gas feedstock in late 2020 and in 2021 after being connected to India's gas grid. In 2022 demand growth is expected to accelerate to nearly 8% on the back of strong GDP growth, expanding infrastructure, rising domestic production (which comes at a lower cost than imported LNG) and a supportive policy environment. However, high LNG prices could present continuing headwinds to India's gas demand recovery in 2022.

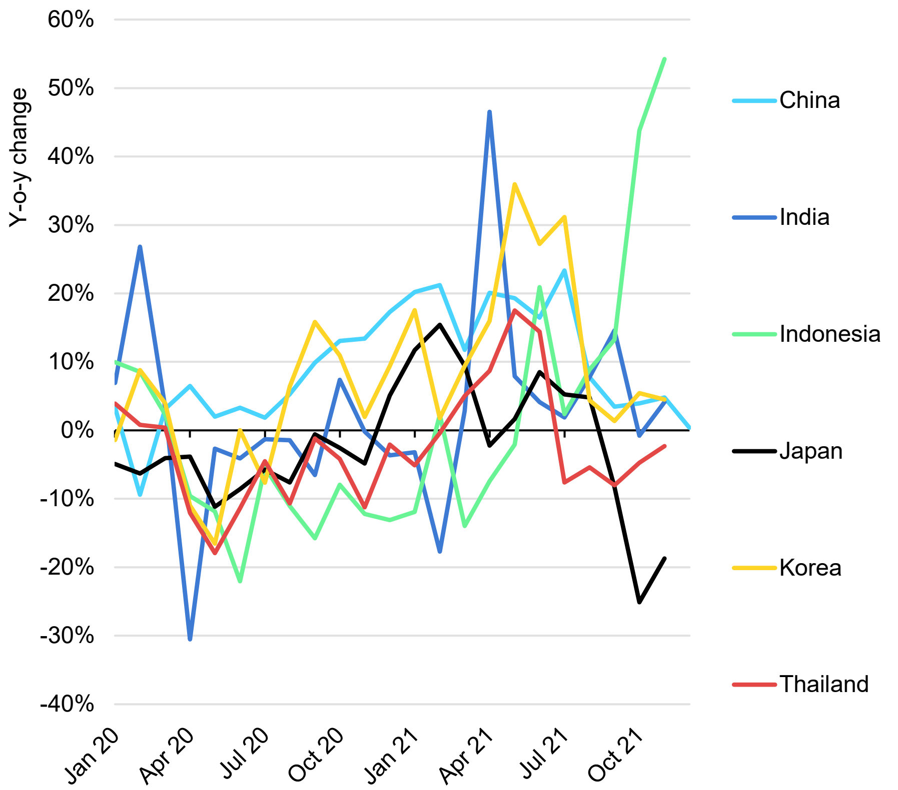
Japan's total gas consumption in 2021 is estimated to have remained flat relative to 2020. In the first nine months of 2021 gas demand increased by 6% y-o-y, driven by strong growth in the power and residential sectors during a cold spell in Q1 and by growing industrial gas demand throughout most of the year. City gas sales for industrial use increased by 8% in the first nine months, according to data from METI. The strong growth trend in the first three quarters of 2021 is expected to have reversed in Q4 as a series of nuclear restarts (more than doubling output from a year earlier) reduced gas burn. These kept overall demand for 2021 broadly unchanged from the previous year. In 2022 total consumption is projected to decrease by 2%, as the positive demand effect from an ongoing economic recovery is more than offset by lower gas use in the power sector due to higher nuclear and renewable generation.

Korea's total gas demand is on course to increase by a notable 12% in 2021. In the first nine months of the year consumption was up by 14% y-o-y, driven by rapid growth in the power generation and city gas sectors. Gas demand in these two sectors increased by 23% and 8% y-o-y, respectively, during the first three quarters. Strong demand in the power sector resulted from a robust economic recovery and the temporary shutdown of several coal-fired power plants and nuclear reactors. In Q4 the addition of a new nuclear unit and milder temperatures than in 2020 are expected to have slowed the growth in gas demand. In 2022 total consumption in Korea is projected to decrease by 1% due to higher nuclear generation and the assumed resumption of normal winter weather.

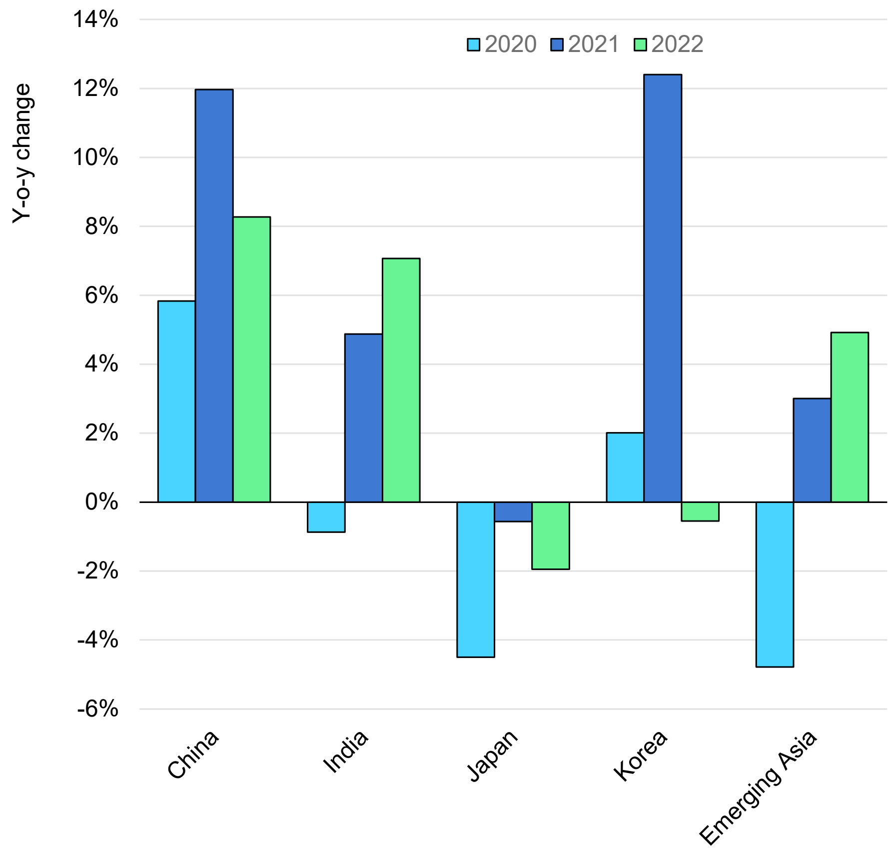
Emerging Asia's gas consumption is set to have increased by a modest 3% in 2021 as high prices and resurgent waves of Covid-19 kept demand growth in check. Indonesia, the biggest gas market in emerging Asia, saw nearly 9% y-o-y demand growth in the first eleven months of 2021. Thailand, the number two consumer in emerging Asia, posted strong y-o-y gains in H1 2021, but saw substantial y-o-y declines in H2 as high prices suppressed demand. High LNG prices also triggered fuel switching away from gas, especially in Pakistan and Bangladesh, but strong power demand and domestic gas production declines in both countries meant that LNG import growth continued even amid record-high spot LNG prices. In 2022 gas demand in emerging Asia is projected to increase by 5%, driven by the economic recovery from Covid-19 and the accompanying increase in electricity demand.

Asia's uneven gas demand recovery continues from 2021 into 2022

Monthly gas demand in selected Asian countries (2020-2021)



Gas demand in selected Asian countries (2020-2022)



Sources: IEA analysis based on ICIS (2022), ICIS LNG Edge; CQPGX (2022), Nanbin Observation; JODI (2022), Gas World Database; PPAC (2022), Gas Consumption; EPPO (2022), Energy Statistics.

US natural gas producers did more with less in 2021

US natural gas production managed to grow in 2021 in spite of the combined constraints of a sluggish increase in domestic consumption, capacity outages during the cold spells in February and the Gulf Coast hurricanes in late Q3, and conservative spending by upstream companies. First estimates indicate a less than 2% y-o-y increase, a far cry from the strong growth rates of 2018 and 2019 (up 13% and 10% respectively), but just sufficient to offset last year's decline and return to 2019's annual dry gas production level.

Operational optimisation supported production growth

Natural gas-driven drilling activity recovered from 2020's decline, oscillating around the 100 rigs mark since May 2021 and reaching 106 in late December – compared to an average of 110 active rigs in the first quarter of 2020 just before the beginning of the Covid-19 pandemic. Drilling activity remains, however, much lower than in the first half of 2019, which registered above 190 active gas drilling rigs on average. This is particularly visible in the Appalachian Basin, where an average of 70 wells were drilled per month over the fourth quarter of 2021, compared with a record of 142 in May 2019. In spite of this drop in drilling activity, natural gas output from the Appalachian Basin increased by close to 20% between mid-2019 and Q4 2021.

This contrast is explained by higher completion rates and increased operational optimisation to maximise output. The number of wells completed per month jumped from an average of 60 in Q4 2020 to close to 100 in Q4 2021 in the Appalachian. This is possible due to the strong build-up of drilled but uncompleted (DUC) wells in recent years now being tapped by upstream companies. In 2021 the Appalachian DUC inventory declined by about 25%. Operators active in the basin have also mentioned an acceleration in drilling and completion times allowing them to ramp up production.

Activity in other gas-driven basins has also recorded strong growth, with an average 7% y-o-y increase during the first 11 months of 2021. This was led by the Haynesville play, which saw its output grow by 13% y-o-y thanks to growing feedgas needs from neighbouring Gulf of Mexico LNG export plants.

Gas output from oil-driven basins benefited from rising tight oil production. In the Permian, the most prolific associated gas-producing basin, daily average tight oil output increased by close to 13% between January and November, while associated natural gas production grew by almost 15% over the same period. Gas production also increased in the Woodford and Bakken plays, while declining sharply in the Eagle Ford and Fayetteville.

Further optimisation of daily production operations also enabled the US upstream industry to squeeze more gas out of existing wells and improve production volume management. EQT Corporation, a major US natural gas producer, reported restricting initial output from all new wells (known as “choking back”) for the first six to nine months of operation to allow for short-term production swings while improving longer-term production capacity. Other producers also mentioned in their quarterly presentations some production efficiency gains in operational performance, including improved well pressure management and wellbore cleanout programmes.

Further growth is expected for 2022 despite confirmed capital discipline

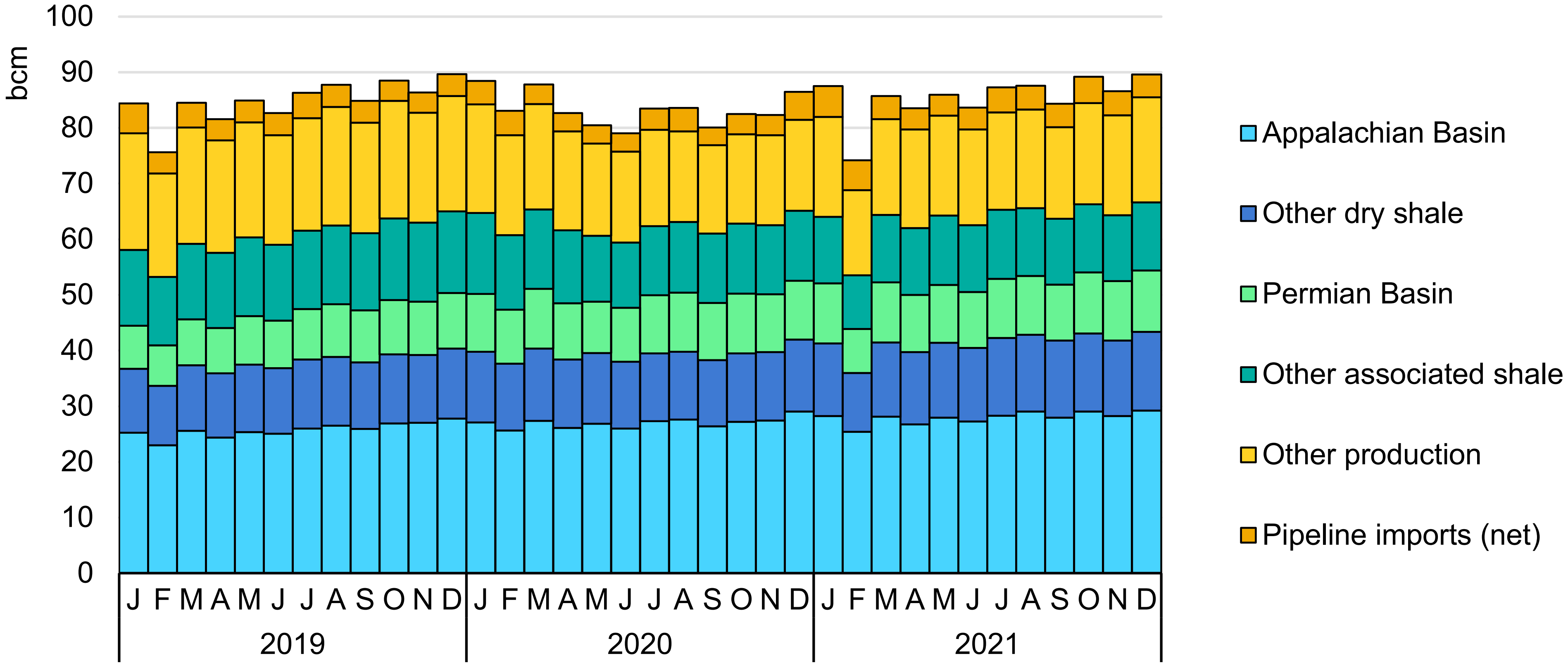
The first half of January 2022 showed a 3% decline in shale output compared to late December 2021, with lower production levels from both the Appalachian and Permian basins. While production drops are not unusual at the start of the year, these coincided with colder temperatures that pushed up gas demand in the residential sector, leading to a relative tightening of the US natural gas balance. A cold spell over the New Year weekend coincided with a temporary drop in Permian gas output in Texas; the Texas Railroad Commission assured in a statement that this temporary drop did not have any real impact on the gas market or the grid.

US natural gas production is forecast to grow by close to 3% in 2022, although large, listed US upstream companies have confirmed guidance that capital return is being prioritised over growth. Additional productivity improvements can still be expected in spite of capital discipline, although it is likely that the most easily achieved gains have already been realised. The increase in mergers and acquisitions activity in the second half of 2021 may provide additional optimisation opportunities once merged assets are consolidated in the course of 2022. DUC wells also provide further least-cost potential to develop gas production in 2022, while privately owned upstream operators are likely to be more reactive to price opportunities if the North American futures curves show positive pricing potential.

The other source of growth comes from associated natural gas production. The IEA Oil Market Report projects US crude oil output to rise from 11.2 mb/d in 2021 to 12.0 mb/d in 2022; any increase in light tight oil output results in a proportional growth in associated shale gas production.

US natural gas production ends 2021 at its highest monthly level since December 2019

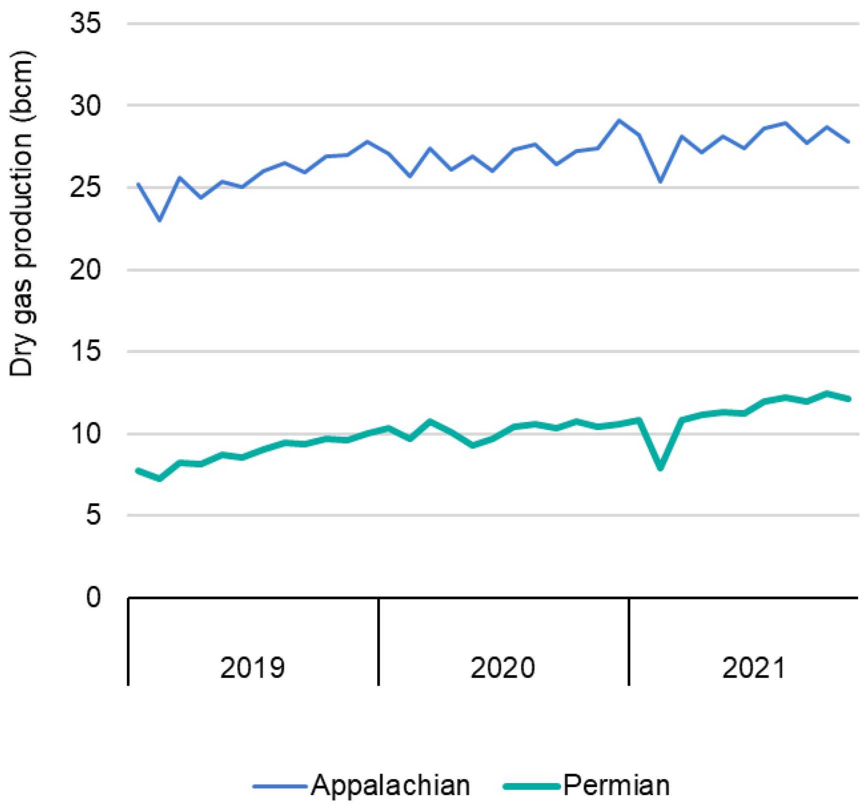
Gas supply by type in the United States (2019-2021)

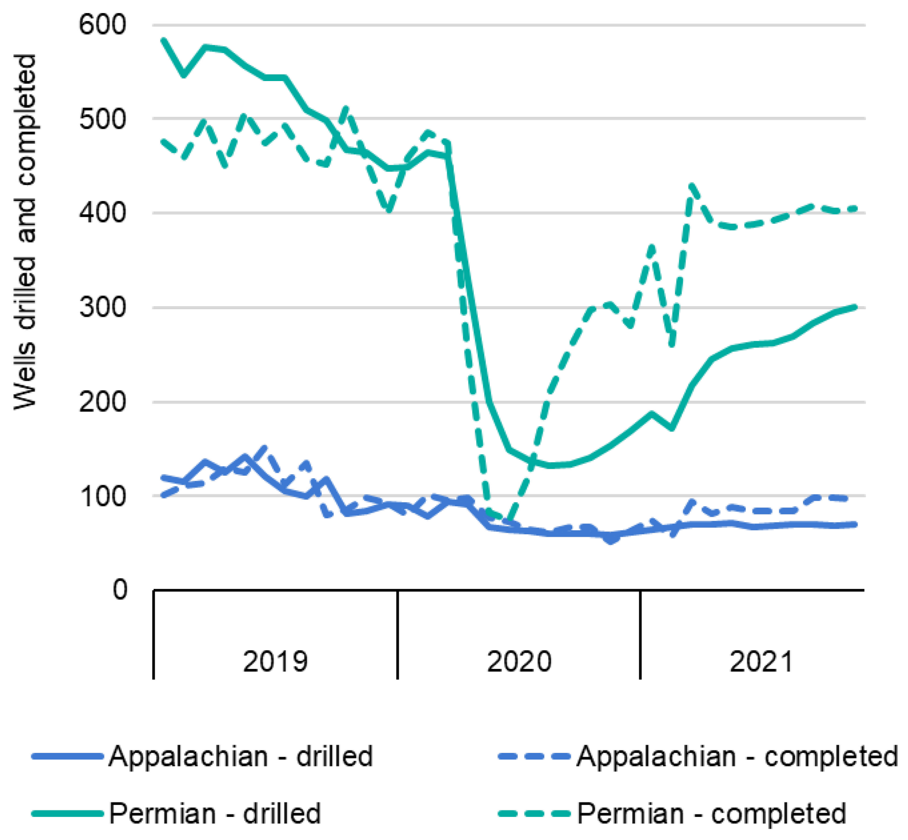


Sources: IEA analysis based on EIA (2022), Natural Gas Data; Natural Gas Weekly Update.

Despite stable drilling, production kept growing in the Appalachian Basin in 2021 thanks to high completion rates, while completion stabilised in the Permian in spite of increased drilling

Dry gas production and well drilling and completion activity in the Appalachian and Permian basins (2019-2021)

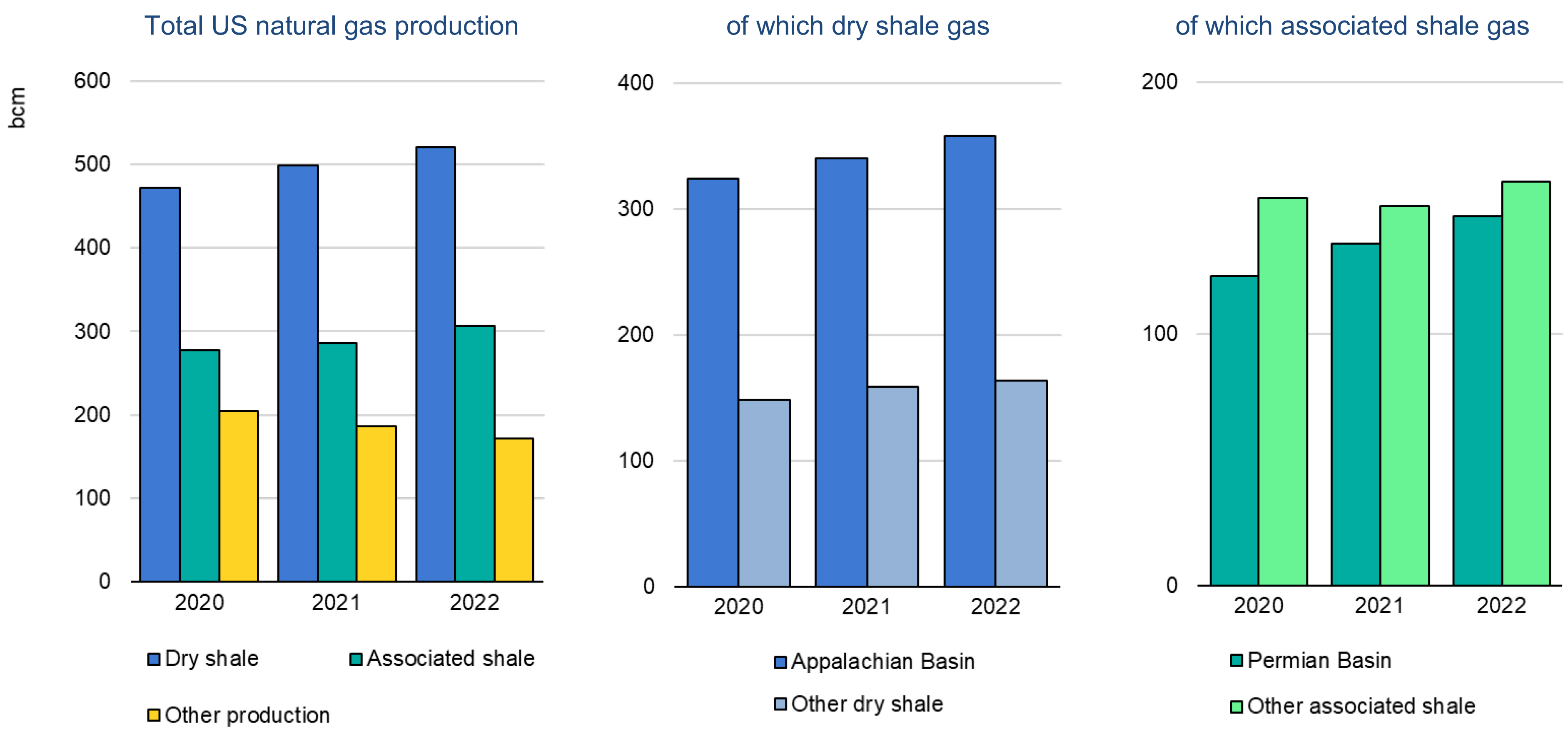




Sources: IEA analysis based on EIA (2022), Natural Gas Data; Natural Gas Weekly Update.

US dry gas production is expected to keep growing in 2022, driven by the Appalachian Basin and further associated shale gas volumes

Dry gas production by main source in the United States (2020-2022)



Sources: IEA analysis based on EIA (2022), Natural Gas Data; Natural Gas Weekly Update.

Eurasia’s natural gas production grew by a record amount in 2021…

Eurasia’s natural gas production grew by an estimated 10% (or 90 bcm) y-o-y in 2021 – its largest annual increase since the fall of the Soviet Union. This strong growth was supported by high domestic demand, restocking needs and recovering exports.

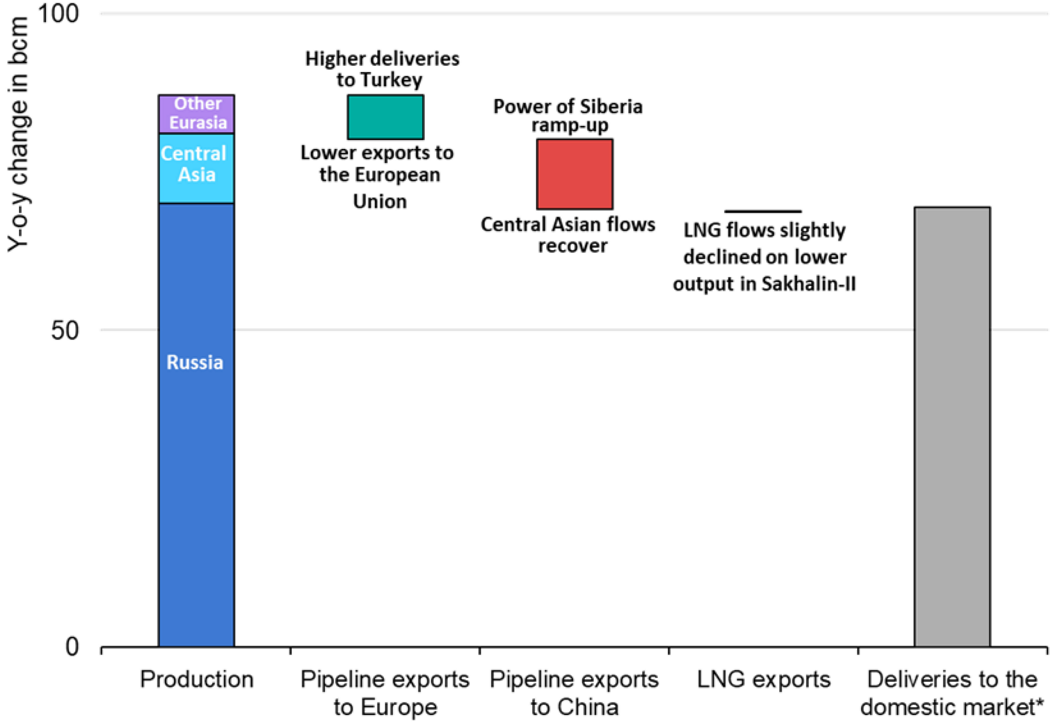
Russia’s natural gas output is estimated to have risen by 10% (or 70 bcm) y-o-y in 2021 to reach a record of 762 bcm. Gazprom alone accounted for 80% of incremental gas production, with its output nearing 513 bcm – its highest level since 2008, although below the company’s official production capacity of 550 bcm. **Domestic demand surged** by an estimated 10% y-o-y. This was partly driven by colder winter and spring temperatures at the beginning of 2021, robust growth in thermal power generation (up by 12% y-o-y) and a gradual recovery in economic and commercial activity. Besides strong domestic demand, **storage injections rose to a record** 60 bcm, necessary to meet Russia’s storage target of 72.6 bcm by the beginning of November. Russia’s net **pipeline exports to Europe** increased by 4% y-o-y, but remained 4% below their 2019 levels. These exports were entirely driven by Turkey (up by over 60% y-o-y), while deliveries to the European Union fell by 3% y-o-y due to lower transit flows via Belarus and Ukraine. Pipeline **deliveries to China** via Power of Siberia more than doubled compared to 2020, reaching 10 bcm. Russia’s **LNG exports** declined by 0.5% y-o-y, due to lower supplies from Sakhalin II LNG.

Central Asia’s pipeline deliveries to China increased by 12% y-o-y in the first 11 months of 2021, albeit remaining below their 2019 levels. The recovery was particularly strong in the second half of 2021, with export flows rising by 20% y-o-y between July and November, supported by a widening discount to spot LNG prices. **Azeri gas** production rose by close to 20% y-o-y in the first 11 months of 2021. Pipeline deliveries to Turkey fell by almost 30%, more than compensated by exports to the rest of Europe via the TAP pipeline, which rose to over 8 bcm. **Ukraine**’s domestic production declined by 2% y-o-y in 2021.

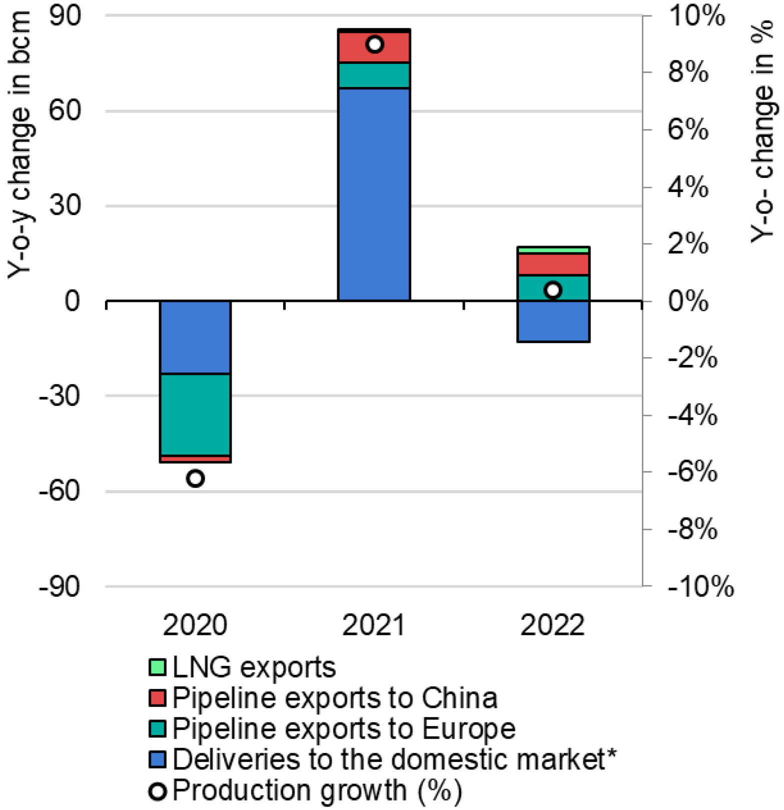
Following the strong increase in 2021, **Eurasia’s gas supply growth is expected to moderate** to below 1% in 2022, almost entirely driven by exports. This forecast assumes a return to average weather conditions and storage cycles in 2022. Consequently, deliveries to the domestic market (including storage injections) are expected to marginally decline compared to 2021. Russia’s net pipeline exports to Europe are expected to oscillate in the range of 170 to 180 bcm, while Central Asian pipeline deliveries to China are set to hover in the range of 40-45 bcm. Exports via Power of Siberia are set to ramp up to 15 bcm, while Azeri flows to Europe via the TAP pipeline are expected to reach 10 bcm in 2022. LNG exports are foreseen to increase by 5% with the full ramp-up of Train 4 at Yamal LNG and the commissioning of Portavaya LNG.

…supported by strong domestic demand growth and recovering exports

Estimated change in Eurasia's natural gas balance (2020-2021)



Eurasia's natural gas balance (2020 – 2022)



* Including net storage injections.

Sources: IEA analysis based on ENTSOG (2022), Transparency Platform; Eurostat (2022), Imports of Natural Gas by Partner Country – Monthly Data; General Administration of Customs of People's Republic of China (2022), Customs Statistics; ICIS (2022), ICIS LNG Edge.

Global LNG trade growth reached 6% in 2021, but slows to 4% in 2022

In 2021 global LNG trade expanded by 6%, a sharp acceleration from the 2020 growth rate of just 1%. LNG import growth in 2021 was led by Asia, which experienced cold weather and a strong economic recovery. China's imports were up by 17%, overtaking Japan for the first time as the world's largest LNG importer, and Korea's were up by 14%. India's LNG imports declined by 11%, but this was largely offset by growth in Bangladesh (up 31%), Pakistan (up 16%) and Thailand (up 16%), fuelled by strong power demand and economic activity. Central and South America was also a key growth driver (up 69%) due to a severe drought in Brazil, which led to a more than threefold increase in LNG imports there. European inflows declined by 5% as strong demand in Asia drew cargoes away. North America continued to lead global LNG export growth with a 51% increase in 2021. Exports from Australia grew by 3% (despite continuing outages), while deliveries from Qatar and Russia remained broadly stable at elevated levels. Egypt registered a more than fourfold increase in LNG outflows thanks to the restart of exports from Damietta. The biggest export declines occurred in Trinidad and Tobago, Nigeria and Norway.

In Q4 2021 the rate of growth in global LNG trade accelerated to 8% y-o-y, a marked increase from a rate of just 5% in the first three quarters of 2021. Unlike the first three quarters (when Asia was the main driver), Q4 growth was fuelled by European inflows, which were up by 40% y-o-y due to reduced pipeline imports and domestic production. This is a sharp contrast to the 17% y-o-y decline in European inflows in Q1-Q3 2021. Asian LNG imports were flat y-o-y in Q4 due to the soaring spot price of LNG and heavier than usual stock building in Northeast Asia ahead of the winter months. Imports into China, Japan and Korea combined were up by 14% y-o-y in Q1-Q3, but decreased by 0.4% y-o-y in Q4. On the supply side, higher volumes of LNG trade were enabled by recovering production in countries previously beset by outages (e.g. Australia, Peru), as well as by continuing production increases in the United States and Russia in particular.

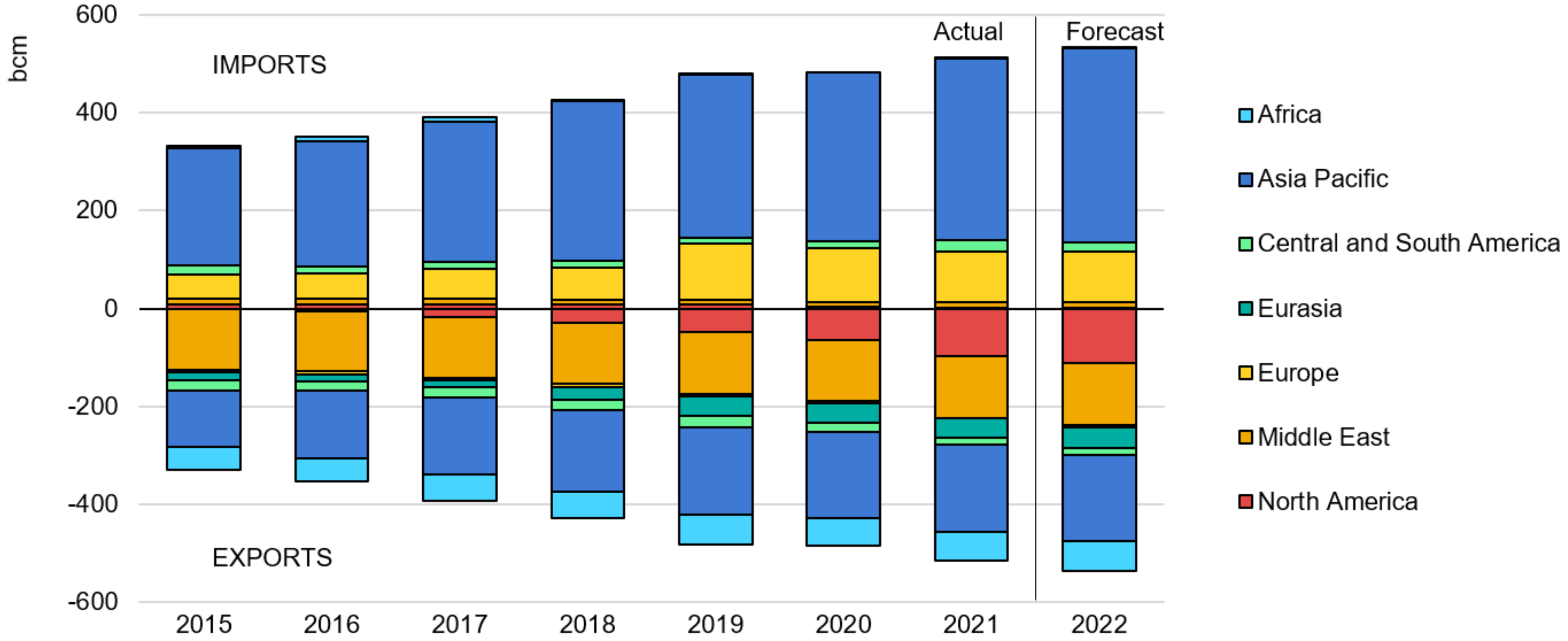
In 2022 global LNG trade growth is projected to slow to 4% as the demand expansion in Asia during 2021 moderates and the drought-driven rise in South American imports reverses. Asia accounts for all net growth in LNG imports. China remains the single largest country contributor to import growth, but its growth rate drops to 9% in 2022 due to the ramp-up of pipeline flows from Russia and the overall slowdown in gas demand growth. India's LNG imports are projected to return to their 2020 levels after a temporary dip in 2021, and register a 12% increase in 2022. LNG inflows to emerging Asia are set to expand by 27%, driven by the region's post-Covid demand recovery, domestic production declines and planned import capacity additions. European inflows are also expected to remain elevated in 2022 – although likely below 2019-2021 levels – to meet the region's high restocking needs.

Import growth in the Middle East during 2022 (up 11%) is enabled in part by Kuwait's new Al-Zour terminal, while in Africa it is fuelled by the emergence of new importing countries – Ghana, South Africa and Senegal. Central and South America's sharp 20% decline is largely due to the normalisation of hydro reservoir levels in Brazil after severe droughts in 2021.

LNG export growth in 2022 remains dominated by North America, which accounts for more than 75% of the net increase in global LNG supply. The commercial start of Sabine Pass train 6 and the Calcasieu Pass terminal (both ahead of schedule) are the main contributors to a 16% (16 bcm) increase in US LNG production in 2022. European exports are set to increase by about 4 bcm on the planned restart of Norway's Hammerfest terminal in Q2 2022. The rest of the world remains broadly flat. Small increases in South America (due to recovering output in Trinidad and Tobago and Peru), Russia (due to the start-up of Portovaya LNG) and Africa (due to the launch of Coral FLNG in Mozambique) are offset by declines in Asia Pacific (despite the addition of the Tangguh LNG train 3 expansion in Indonesia) and the Middle East.

Asia Pacific drives LNG import growth and North America leads LNG export growth in 2022

LNG imports and exports by region (2015-2022)



Source: IEA analysis based on ICIS (2022), ICIS LNG Edge.

LNG inflows into Europe recovered strongly in Q4 2021…

Europe's natural gas supply picture remained tight throughout Q4 2021. Pipeline deliveries from Russia fell significantly year-on-year, while Europe's domestic production continued to decline, leaving additional market space for LNG inflows and alternative pipeline suppliers.

LNG inflows grew by a remarkable 40% y-o-y during Q4, following a drop of 17% y-o-y during Q1-3 2021. Stronger LNG deliveries were primarily driven by higher imports from the United States, alone contributing almost 40% of net growth in LNG supplies, followed by Egypt and Qatar. Southern Europe accounted for over 60% of LNG import growth, with strong inflows into Turkey and Spain. For 2021 as a whole, European LNG imports fell by 4% y-o-y, and the United States was the region's largest LNG supplier.

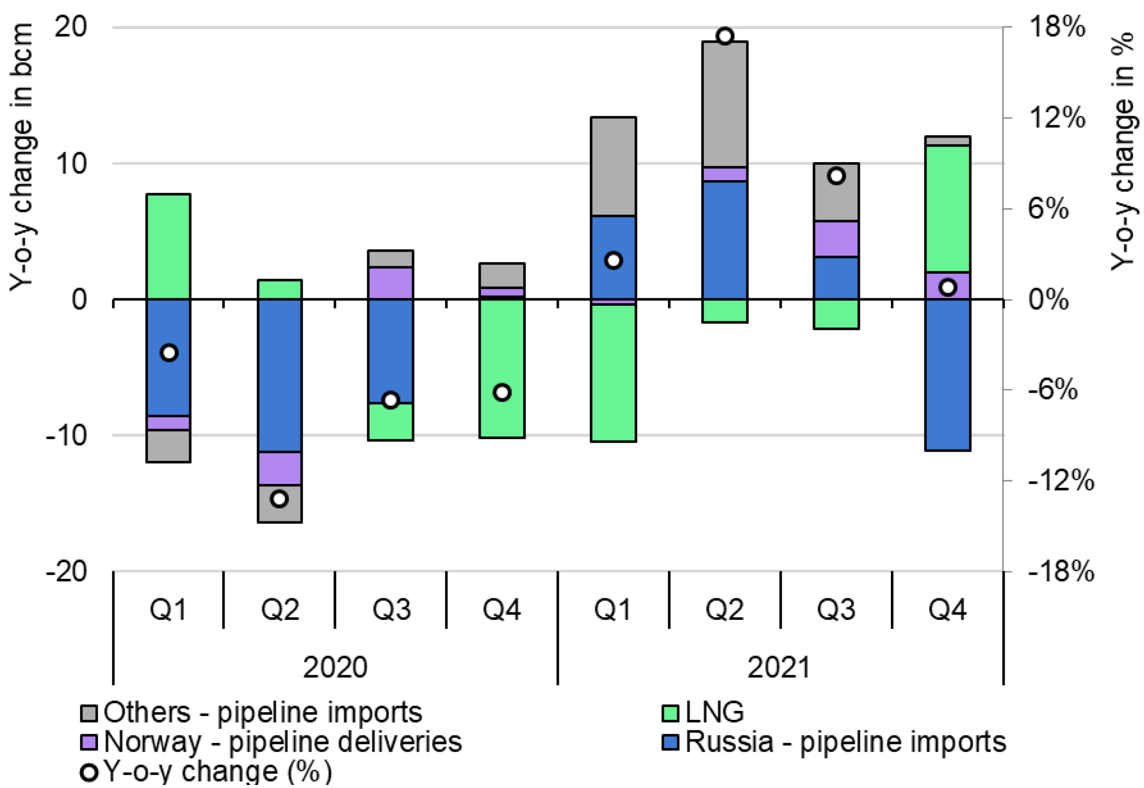
Russia's pipeline exports declined by close to 25% y-o-y in Q4, due to lower transit flows via Belarus and Ukraine and reduced deliveries to Turkey (down by an estimated 25% y-o-y). Despite this, for 2021 overall, Russia's pipeline exports to Europe still rose by 4% y-o-y, although entirely driven by Turkey (up by over 60% y-o-y), while flows to the European Union declined by 3% y-o-y. Gazprom has also reduced its exposure to short-term sales, with no day-ahead auctions carried out on the company's electronic sales platform during Q4.

Europe's non-Norwegian domestic production continued to decline, falling by 10% y-o-y during July-November, largely driven by lower output in the Netherlands and the United Kingdom. In contrast, Norway's pipeline supplies to the rest of the continent grew strongly, up by 7% y-o-y in Q4. This was largely supported by higher gas flows to Germany (up by over 45% y-o-y), at a time when pipeline imports from Russia to Germany via Belarus fell by 80% y-o-y. For 2021 in full, Norway's pipeline deliveries to the rest of Europe rose by 5% y-o-y. Pipeline supplies from North Africa remained flat during Q4 y-o-y, although flows to Iberia in the quarter declined by 20% y-o-y following the end of flows via the Maghreb–Europe pipeline on 1 November. Azeri pipeline supplies to the European Union rose to over 8 bcm in 2021.

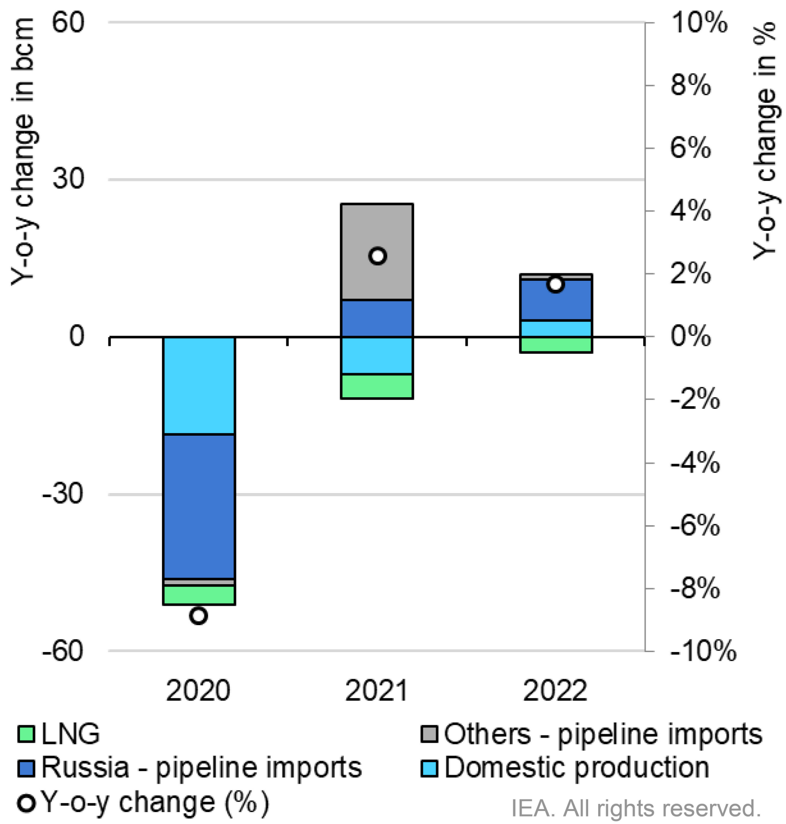
Europe's domestic production is expected to remain close to the previous year's levels in 2022, as lower gas output on the continent is expected to be compensated by recovering gas production in the United Kingdom and Norway. Europe's import requirements are expected to increase by close to 2% compared with 2021, despite its gas demand declining by over 4% y-o-y. This will be largely driven by restocking needs, with the region's underground storage sites standing 15 bcm below their five-year average at the beginning of January. Europe's LNG imports are set to decline only marginally in 2022. Azeri supplies via TAP are set to reach 10 bcm in 2022.

…amid lower pipeline deliveries from Russia

Estimated change in Europe's quarterly natural gas imports and deliveries from Norway (2020-2021)



Change in Europe's natural gas supply (2020-2022)



Sources: IEA analysis based on ENTSOG (2022), Transparency Platform; Eurostat (2022), Energy Statistics; Gas Transmission System Operator of Ukraine (2022), Transparency Platform; GIE (2022), ICIS LNG Edge; JODI (2022), Gas World Database; Norwegian Petroleum Directorate (2022), Monthly Production Figures.

Asian and European spot gas prices, together with LNG spot charter rates, surged to all-time highs in Q4 2021…

Tight supply–demand fundamentals, low underground storage levels in Europe, LNG outages and infrastructure uncertainty drove Asian and European spot prices to record highs in Q4 2021, while in the United States Henry Hub rose to decade highs.

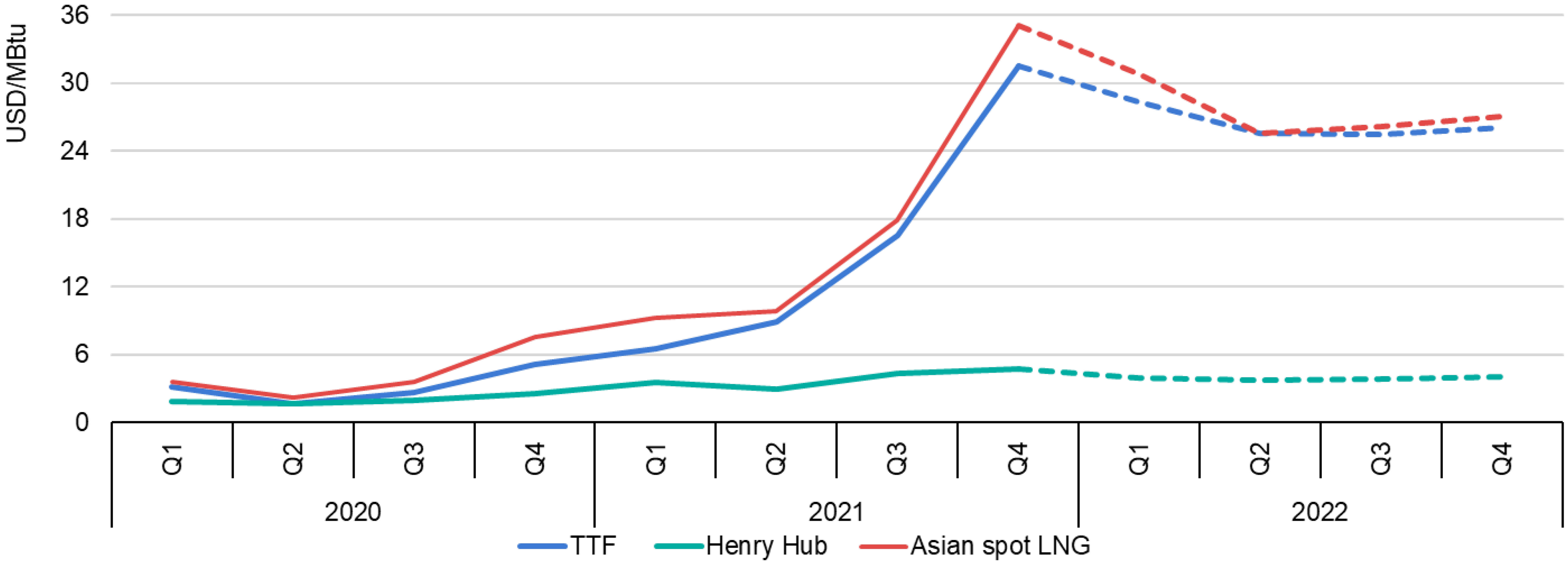
In Europe, **TTF** prices averaged USD 31.5/MBtu in Q4 2021, a more than sixfold increase compared with the same period in 2020. Lower pipeline deliveries from Russia (down by 25% y-o-y) and declining domestic production tightened European gas supply, which together with low storage levels led to upward pressure on gas prices. Gas prices surged to an all-time high of close to USD 60/MBtu on 21 December, when the region faced its first winter cold spell. Prices have moderated since then, averaging below USD 30/MBtu in the first half of January, although remaining highly volatile. **Asian spot LNG** prices followed a similar trajectory, reaching an all-time high quarterly average of USD 35/MBtu in Q4 – an almost fivefold increase compared with the same period in 2020. This was partly driven by the strong competition with the European market for spot LNG cargoes. LNG feedgas supply issues in Malaysia and Indonesia, together with unplanned outages and repairs in Australia (Gorgon LNG, Prelude FLNG), further tightened winter gas supply to the Northeast Asian market. Japan and Korea's LNG import prices averaged USD 14/MBtu during October and November, their highest level for this period of the year since 2014. In the United States, **Henry Hub** prices averaged USD 4.8/MBtu in Q4, their highest quarterly average since 2008. Prices surged in October to above USD 6/MBtu, before moderating to below USD 4/MBtu during December on unseasonably mild temperatures and recovering natural gas production.

LNG spot charter rates rose by more than 50% y-o-y to average at a record USD 170 000/day in Q4 2021. This was supported by the rapid expansion of US–Northeast Asia trade, leading to higher tonne-mile demand and congestion on the Panama Canal in October and November.

Forward prices as of the beginning of January indicate that the high gas price environment is expected to last into 2022. In Europe and Asia spot prices are foreseen to average USD 26 and USD 27/MBtu respectively – both all-time high annual averages. Prices are expected to decline in the second half of 2022 on improving supply availability, although remaining well-above historical averages in both markets. Restocking needs in Europe and lower liquefaction capacity additions are set to exert upward pressure on gas prices. In the United States, Henry Hub prices are expected to average close to their 2021 levels, at USD 4/MBtu.

…with forward curves indicating the high gas price environment lingering into 2022

Main spot and forward natural gas prices (2020-2022)



Sources: IEA analysis based on CME (2022), Henry Hub Natural Gas Futures Quotes; Dutch TTF Natural Gas Month Futures Settlements; CME Group (2022), LNG Japan/Korea Marker (Platts) Futures Settlements; EIA (2022), Henry Hub Natural Gas Spot Price; ICIS (2021), ICIS LNG Edge; Powernext (2022), Spot Market Data.

Tight primary gas supply led to higher storage withdrawals in Europe in Q4 2021…

Underground gas storage sites opened Q4 with below-average inventory levels both in Europe and North America, as tight summer market fundamentals weighed on net injection in 2021.

Storage levels in **Europe** stood 17% (or 15 bcm) below their five-year average on 1 October. Inventories have been particularly low in northwest Europe, standing at just 67% of their working storage capacity (excluding France). As a consequence of tight summer–winter spreads (USD 0.2/MBtu), net injections fell 18% below their five-year during Q2 and Q3. This, together with low opening stocks after the 2020/21 winter, led to low fill levels at the beginning of the heating season. Storage sites turned to net withdrawals for the first time on 13 October – seven days before the five-year average. Net storage withdrawals in Europe averaged 24% above their five-year average during Q4 2021, amid lower primary gas supply and resilient gas demand. Consequently, European underground storage sites had fallen to a level 23% (or 22 bcm) below their five-year average by the beginning of January 2022, standing below 55% of their working storage capacity.

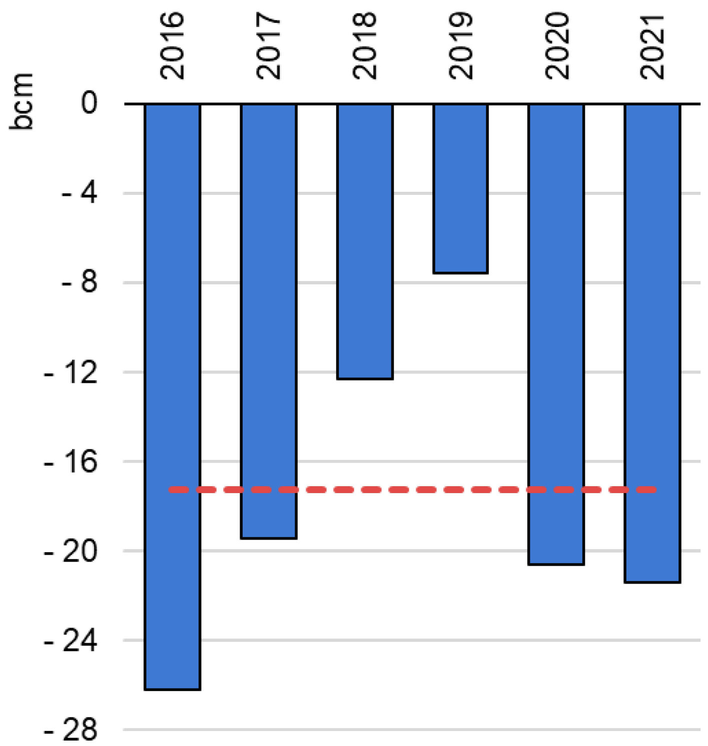
In Russia, Gazprom's net injections surged to a record of over 61 bcm in 2021, with the company reaching its 72.6 bcm fill target by the beginning of November. Despite strong domestic demand and high export revenue potential, Gazprom's withdrawals in Q4 fell by 40% y-o-y and 27% below their five-year average. In Ukraine, gas inventory levels stood at 50% of working capacity at the beginning of October. Net storage withdrawals rose by 13% y-o-y in Q4 amid lower imports from the European Union. Consequently, the country's storage levels had fallen below 30% of the working capacity by the beginning of January 2022 according to data from Gas Infrastructure Europe.

In the United States, storage levels stood 5% below their five-year average at the beginning of October 2021, but had moderated to 2% by the start of November as a consequence of strong injections. Unseasonably mild winter temperatures in December reduced space heating requirements, which with a gradual recovery in domestic production resulted in withdrawal rates falling to almost a quarter of their five-year average in Q4. Consequently, storage levels stood 3.1% above their five-year average at the end of 2021. In Canada, storage levels stood 1% above their five-year average at the beginning of October. Net withdrawals were 16% above their five-year average in Q4. Consequently, Canada's gas storage levels deteriorated to stand 1% below their five-year average at the end of 2021.

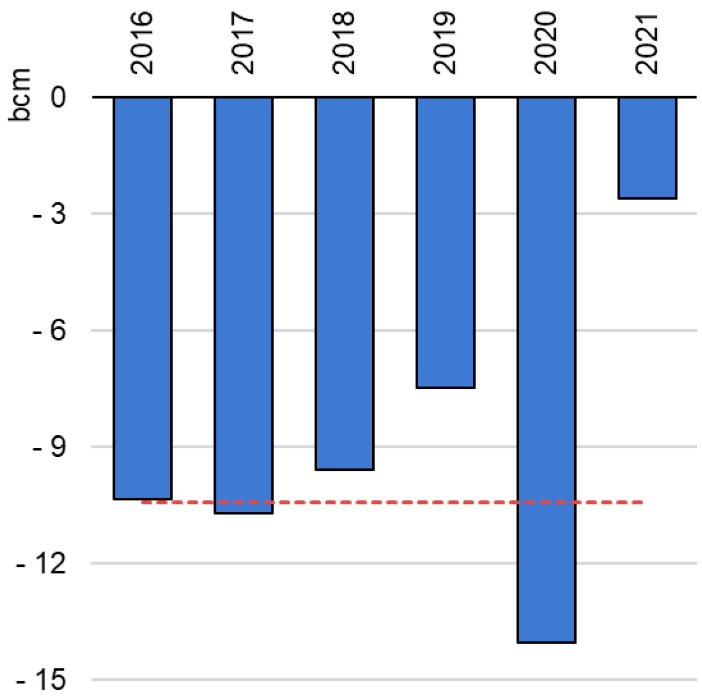
In Japan and Korea, closing LNG stocks stood 2% above their five-year average in November, as both countries have adopted a more conservative approach to LNG stock holding and monitoring. LNG stocks held by Japan's power generation companies stood 20% above their four-year average by mid-January 2022.

…while storage withdrawals were below average in the United States

Net storage withdrawals in Europe in Q4 (2016-2021)

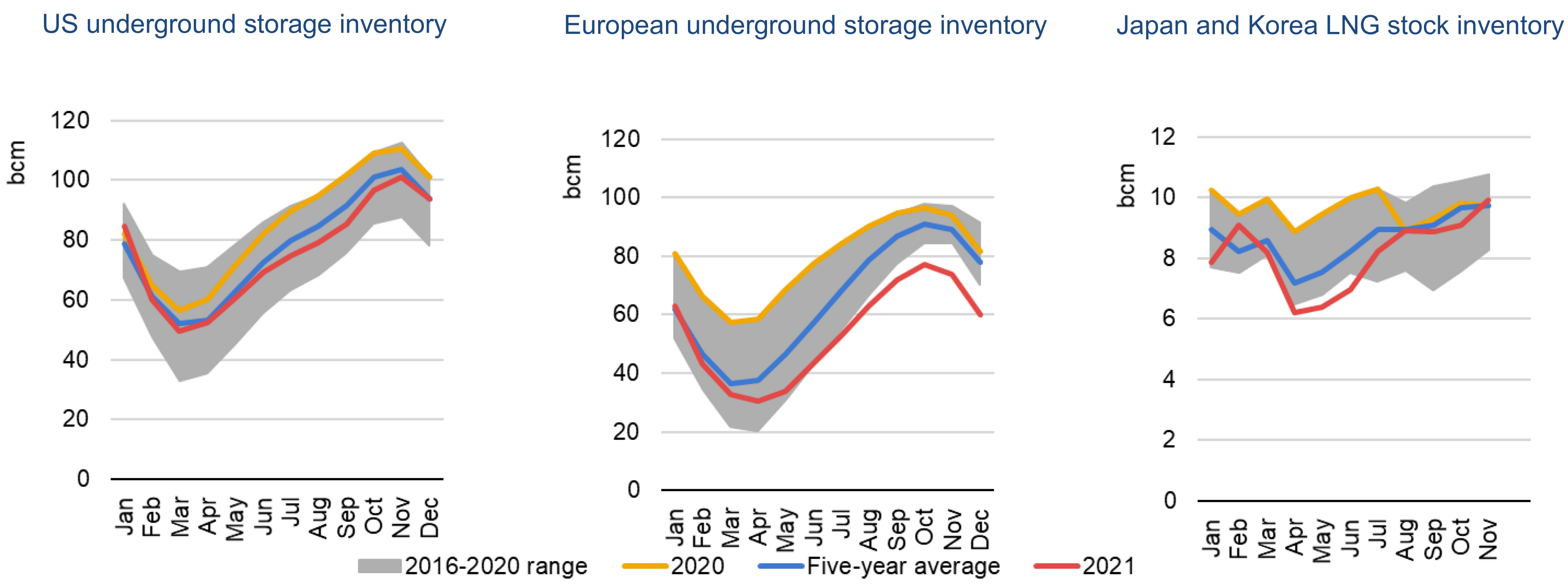


Net storage withdrawals in the United States in Q4 (2016-2021)



Sources: IEA analysis based on EIA (2022), Weekly Working Gas in Underground Storage; GIE (2022), AGSI+ Database.

Storage levels in Europe fell to below 55% of their working capacity at the beginning of January, while inventory levels in the United States stayed close to their five-year average



Sources: IEA analysis based on EIA (2022), Weekly Working Gas In Underground Storage; GIE (2022), AGSI+ Database; IEA (2022), Monthly Gas Data Service.

Annex

Summary table

World natural gas demand and production by region and key country (bcm)

	Demand					Production				
	2018	2019	2020	2021	2022	2018	2019	2020	2021	2022
Africa	157	162	164	173	179	248	252	248	266	272
Asia Pacific	824	846	850	904	950	627	654	638	659	673
of which China	*283*	*307*	*325*	*364*	*394*	*160*	*174*	*189*	*206*	*219*
Central and South America	153	152	140	151	151	173	169	155	161	161
Eurasia	666	658	633	687	666	932	941	886	973	977
of which Russia	*493*	*482*	*460*	*510*	*486*	*726*	*738*	*692*	*761*	*763*
Europe	536	537	522	552	527	246	227	211	204	207
Middle East	544	546	548	564	583	666	677	671	693	709
North America	1 061	1 097	1 070	1 079	1 091	1 062	1 172	1 149	1 166	1 191
of which United States	*854*	*888*	*869*	*872*	*881*	*868*	*968*	*954*	*972*	*998*
World	**3 940**	**3 996**	**3 926**	**4 109**	**4 148**	**3 954**	**4 092**	**3 957**	**4 122**	**4 191**

Regional and country groupings

Africa – Algeria, Angola, Benin, Botswana, Cameroon, Congo, Democratic Republic of the Congo, Côte d'Ivoire, Egypt, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Libya, Morocco, Mozambique, Namibia, Nigeria, Senegal, South Africa, Sudan, United Republic of Tanzania, Togo, Tunisia, Zambia, Zimbabwe and other countries and territories.[1]

Asia Pacific – Australia, Bangladesh, Brunei Darussalam, Cambodia, Chinese Taipei, India, Indonesia, Japan, Korea, the Democratic People's Republic of Korea, Malaysia, Mongolia, Myanmar, Nepal, New Zealand, Pakistan, the People's Republic of China,[2] the Philippines, Singapore, Sri Lanka, Thailand, Viet Nam and other countries and territories.[3]

Central and South America – Argentina, Bolivia, Brazil, Chile, Colombia, Costa Rica, Cuba, the Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Jamaica, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, Trinidad and Tobago, Uruguay, Venezuela and other countries and territories.[4]

Eurasia – Armenia, Azerbaijan, Belarus, Georgia, Kazakhstan, Kyrgyzstan, the Republic of Moldova, Russian Federation, Tajikistan, Turkmenistan, Ukraine and Uzbekistan.

Europe – Albania, Austria, Belgium, Bosnia and Herzegovina, Bulgaria, Croatia, Cyprus,[5,6] Czech Republic, Denmark, Estonia, Finland, the Former Yugoslav Republic of North Macedonia, France, Germany, Gibraltar, Greece, Hungary, Iceland, Ireland, Italy, Kosovo,[7] Latvia, Lithuania, Luxembourg, Malta, Montenegro, Netherlands, Norway, Poland, Portugal, Romania, Serbia, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey and United Kingdom.

European Union – Austria, Belgium, Bulgaria, Croatia, Cyprus,[5,6] Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, the Slovak Republic, Slovenia, Spain and Sweden.

Middle East – Bahrain, the Islamic Republic of Iran, Iraq, Israel,[8] Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, the Syrian Arab Republic, the United Arab Emirates and Yemen.

North Africa – Algeria, Egypt, Libya, Morocco and Tunisia.

North America – Canada, Mexico and the United States.

[1] Individual data are not available and are estimated in aggregate for: Burkina Faso, Burundi, Cape Verde, Central African Republic, Chad, Comoros, Djibouti, Equatorial Guinea, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Madagascar, Malawi, Mali, Mauritania, Mauritius, Niger, Reunion, Rwanda, Sao Tome and Principe, Seychelles, Sierra Leone, Somalia, Swaziland and Uganda.

[2] Including Hong Kong.

[3] Individual data are not available and are estimated in aggregate for: Afghanistan, Bhutan, Cook Islands, Fiji, French Polynesia, Kiribati, the Lao People's Democratic Republic, Macau (China), Maldives, New Caledonia, Palau, Papua New Guinea, Samoa, Solomon Islands, Timor-Leste, Tonga and Vanuatu.

[4] Individual data are not available and are estimated in aggregate for: Antigua and Barbuda, Aruba, Bahamas, Barbados, Belize, Bermuda, British Virgin Islands, Cayman Islands, Dominica, Falkland Islands (Malvinas), French Guyana, Grenada, Guadeloupe, Guyana, Martinique, Montserrat, St. Kitts and Nevis, St Lucia, St. Vincent and the Grenadines, Suriname and Turks and Caicos Islands.

[5] Note by Turkey: The information in this document with reference to "Cyprus" relates to the southern part of the Island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. Turkey recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of United Nations, Turkey shall preserve its position concerning the "Cyprus issue".

[6] Note by all the European Union Member States of the OECD and the European Union: The Republic of Cyprus is recognised by all members of the United Nations with the exception of Turkey. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.

[7] The designation is without prejudice to positions on status, and is in line with the United Nations Security Council Resolution 1244/99 and the Advisory Opinion of the International Court of Justice on Kosovo's declaration of Independence.

[8] The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD and/or the IEA is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

Abbreviations and acronyms

ANP	National Agency of Petroleum, Natural Gas and Biofuels (Brazil)
CME	Chicago Mercantile Exchange (United States)
CNE	National Energy Commission (Chile)
COP	UN Climate Change Conference of the Parties
CO_2	carbon dioxide
CQPGX	Chongqing Petroleum and Gas Exchange (China)
DUC	Drill but uncompleted well
EIA	Energy Information Administration (United States)
ENARGAS	National Gas Regulatory Entity (Argentina)
ENTSOE	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
EPPO	Energy Planning and Policy Office (Thailand)
FERC	Federal Energy Regulatory Commission (United States)
FID	final investment decision
GAIL	Gas Authority of India Limited (India)
GDP	Gross Domestic Product
GMP	Global Methane Pledge
GST	Goods and Services Tax
IEA	International Energy Agency
ICE	InterContinental Exchange
ICIS	Independent Chemical Information Services
JKM	Japan Korea Marker
JODI	Joint Oil Data Initiative
LNG	liquefied natural gas
METI	Ministry of Economy, Trade and Industry (Japan)
MME	Ministry of Mines and Energy (Brazil)
m-o-m	month-on-month
NBP	National Balancing Point (United Kingdom)
NDRC	National Development and Reforms Commission (China)
NERC	North American Electric Reliability Corporation
OGT	Oneok Gas Transmission
OSINERG	Energy Regulatory Commission (Peru)
PPAC	Petroleum Planning and Analysis Cell (India)
PTT	Petroleum Authority of Thailand (Thailand)
TAP	Trans Adriatic Pipeline
TSO	transmission system operator
TTF	Title Transfer Facility (the Netherlands)
USD	United States dollar
w-o-w	week-on-week
y-o-y	year-on-year

Units of measure

bcf/d	billion cubic feet per day
bcm	billion cubic metres
bcm/m	billion cubic metres per month
bcm/y	billion cubic metres per year
GW	gigawatt
mb/d	million barrels per day
MBtu	million British thermal units
mcm	million cubic metres
mcm/d	million cubic metres per day
MW	megawatt
TWh	terawatt hour

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